Morgan Stanley

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MORGAN STANLEY BLUE PAPER

Global Gas

A Decade of Two Halves

Significant LNG overcapacity will persist for five years, pressuring global gas markets … Against consensus, we do not believe that global liquified natural gas markets will tighten in 2011. There are many moving parts, but the key variable is that we believe China will be able to satisfy its own growing gas needs with increased local production. With no major change before 2015 in OECD countries' LNG demand, we believe the 2011 oversupply will persist until mid-decade.

… but then it all tightens—fast. After 2015, falling local production will dominate in Europe, and in China local gas production growth will eventually moderate. Unless major construction investment decisions are taken soon, we forecast the world to become structurally short LNG. By 2020, the shortfall will amount to about 100 million tonnes of liquefaction capacity (or almost 50% of current capacity).

Our counter-consensus view reflects our close analysis of the regional supply-demand mosaic. To understand the regional dynamics and investment opportunities, this report brings together the perspectives of our analysts covering energy, petrochemicals, clean energy, and utilities across the major geographic regions.

Six investment themes: 1) CNOOC, Kunlun Energy, Towngas China, Reliance, and CGG should benefit from domestic production increases in China and India; 2) InterOil, Gazprom, Chevron, Santos, Oil Search, BG, Saipem, and SBM should see new contracts in response to the predicted 2015 gas shortage; 3) Lyondell, Dow, and Petronas Chemicals should receive a boon from low gas prices in the US and Asia; 4) GCL-Poly Energy and Trina Solar are well placed for green growth; 5) ExxonMobil, Statoil, ENI, RWE, and E.ON may face challenges from pricing pressures or contract disputes; and 6) Drax, RWE, E.ON, and CEZ are most exposed to lower power prices in most of Europe.

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Executive Summary

Does the world need more liquefied natural gas? What are the threats to supply and demand? What will happen to regional gas prices over the next few years? These are just some of the questions driving the investment debates in the natural gas industry, where the consensus view is shaped largely by an expectation of expanding demand from all corners well into the forseeable future.

We believe that the market has neglected to factor regional differences into the global supply-demand equation and that the inflection point in global supply is at least five years out. With these assumptions in mind, we look at several industry scenarios and estimate how they might play out by region over time. Of course, some companies will fare better than others under each scenario; we also offer a bottom-up analysis of the companies we have spotted as the long-term beneficiaries.

Our Forecast

Yes, China drives global demand, but ... We agree with the market that because oil is becoming scarcer the world needs more gas. But it is *where* gas is needed that matters: Europe, the US, and Japan will experience relatively modest rises in demand over the next 10 years, at least compared to China that will see a tremendous boost in consumption-driven demand. China alone will account for the bulk of the increase in global demand within the industry.

For LNG markets, the worst is far from over. Consensus expectations for a tighter global LNG market in 2011 are misplaced. We believe that the supply contraction of 2010 and weather-influenced demand hikes were a distortion that has given the market a false sense of security and that the LNG surplus will get worse this summer. Furthermore, we predict that the oversupply will last for five years (exhibit 1).

Supply will tighten … fast. Given current investment plans and our outlooks on regional GDP, pipeline, production, natural-gas vehicles, and power generation, we expect LNG markets to tighten after 2015 as global demand ratchets up. We predict that unless the industry invests in major construction projects soon, the world will be short about 100 million tonnes (mtpa) of liquefaction capacity by 2020 (the world's existing capacity is c.230mtpa, or 30bcf/d). Australia will emerge as the second largest supplier, behind Qatar.

Does Europe need more LNG? Not for five years. Weak European gas markets will last longer than consensus expects and present a challenge for oil-linked gas producers and mid-stream players. Weak gas markets will also dampen the outlook for wholesale power prices in Europe—bad news for most utilities.

Does China need *lots* more LNG? Eventually, but again, not for five years. China has a 10-year track record of successfully increasing its local gas production at double-digit rates. We believe that strong China demand will be met by equally strong local production growth for the next five years.

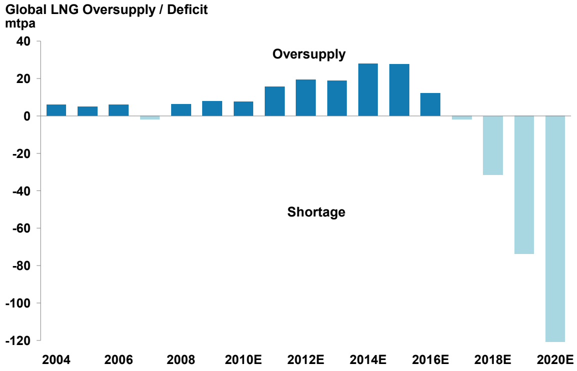
Where is our analysis different?

- We draw on the expertise of senior Morgan Stanley analysts on the global oil and gas, utilities, petrochemicals, and clean energy teams.
- We model all local production, pipe exports, and LNG exports on a bottom-up basis and by region.
- We model regional gas demand in detail by power generation, residential, industrial, and transport sub-sector.
- We consider a wide range of plausible scenarios to see what the key risks to our base case are.

Global gas price dislocations will continue. Spot LNG volumes will stay too low to arbitrage completely the significant regional differences in gas demand-supply balances. Oil linkages will remain a feature of long-term contracts, and oil-linked pricing will persist, but with softer terms and shorter contract durations in emerging Europe.

Exhibit 1

LNG Spare Capacity: Oversupply for Five Years, Then Rapid Tightening



Source: Morgan Stanley Research, E = estimates

Global Gas Overview

If there is one topic that generates more serious debate than oil, it is its lighter cousin—gas. Five years ago, it was clear to all that the US would need materially higher LNG volumes, that tight (unconventional) gas reservoirs would remain economically worthless, and that floating liquefaction was nothing more than … well, a pipe dream.

Times change: Unconventional US gas works in large scale below $4 per million btu. The US possibly turning into a major LNG exporter in this decade. Floating LNG hulls that could open up a new era of stranded gas exploitation. European gas pricing models that survived even the Cold War wobbling in the face of surplus global LNG.

To understand which companies will fare well in gas markets over the next 5–10 years (and which will not), we need to consider all of the pieces of the global gas jigsaw: Liquefaction capacity, local production potential, different regional GDP outlooks, industrial demand shifts, residential penetration changes, renewables construction impact, coal and nuclear capacity changes, and new pipeline supplies, to name but a few (exhibit 2). That is what this reports sets out to do. We also consider what this means for related industries.

This report adds to the detailed liquefaction work the Morgan Stanley Global Energy Team presented in *LNG In A World That's Long Gas* (June 15, 2010). We believe this additional work differentiates our analysis and supports our non-consensus view that whilst the Chinese gas demand picture is immensely bullish, the main beneficiary of this will be the domestic gas exploiters, whereas global gas markets and consequently global LNG markets will see a growing oversupply problem this year. This problem will persist until at least 2015 before a structurally short global LNG environment reasserts itself.

1) **Global gas demand growth is significant, but it is all about China.** Our demand work indicates that OECD nations will report near-flat gas demand until 2015. The real delta is China, which is set to see annual gas consumption rise by 225 billion cubic metres (bcm) to 325bcm (31bcf/d) by 2020, according to our estimates (exhibit 3). India will see a rise in demand of 60bcm per year (6bcf/d) over the same period.

2) **Consensus expects global LNG oversupply to fall in 2011–2012. We disagree.** Supply in the summer of 2010 was distorted by unexpected Qatari maintenance on 9.1mtpa of liquefaction capacity, a situation that we cannot expect to reoccur this summer. If Qatar runs at normal rates, including the Qatargas 3 and 4 project ramp-ups, the country will have 24mtpa (3.1bcf/d) of extra LNG capacity online in summer 2011 versus one year earlier—more than compensating for the temporary 9bcm drop in global supply we have seen resulting from recent unrest in the Middle East/North Africa. Further, a recent contract signed with Centrica indicates Qatar's intentions to increase supply volumes into Europe.

Regional outlook summary – the next five years

Europe: We expect structurally higher gas prices than in the US to make Europe the preferred destination for surplus global LNG. Anticipating only modest local gas demand growth, we believe that LNG will displace further piped imports and that this displacement will drive sustained multi-year pressure on local spot and contract gas terms; these prices will remain above US levels, however.

US: With significant low cost resource available from unconventionals and little change on the policy front to change near-term (2-3 years) demand patterns we expect local prices to remain under pressure and hence for the US to remain an unappealing destination for surplus LNG. A key risk longer term is that the US may become an LNG exporter.

China: Strong gas demand growth will be met by equally strong local production growth, making China less of an LNG importer in the next few years than consensus expects, which in turn extends the global LNG overcapacity challenge.

Australia: Will become the second largest LNG exporter in the world by 2020 and could overtake Qatar if some of the long list of possible projects are sanctioned.

Middle East: Qatar is the world's largest LNG exporter ,but after 2011 we see no further export increases from the region as the focus turns to satisfying strong local gas demand growth (in fact, some Middle East nations will start importing modest volumes of LNG).

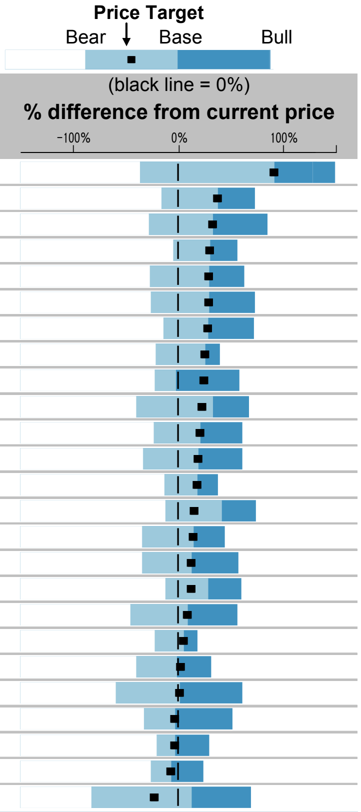
Japan: It is too early to make any conclusion as to how the tragedy of last week's earthquake will alter the near-term Japanese gas demand outlook. For now, there is uncertainty over gas import ability, nuclear station integrity and powergen demand. All we can say is the 9.7GW of nuclear capacity that is currently offline is broadly equivalent to 11mtpa (1.4bcf/d) of LNG into gas fired plants. Even in the unlikely scenario that Japan's nuclear capacity remains offline it would only temporarily reduce the 16-30mtpa global LNG surplus we forecast, not eradicate it.

Exhibit 2

Global Gas: Long-Term Beneficiaries and Potentially Challenged

*** O = Overweight; E = Equal-weight; U = Underweight**

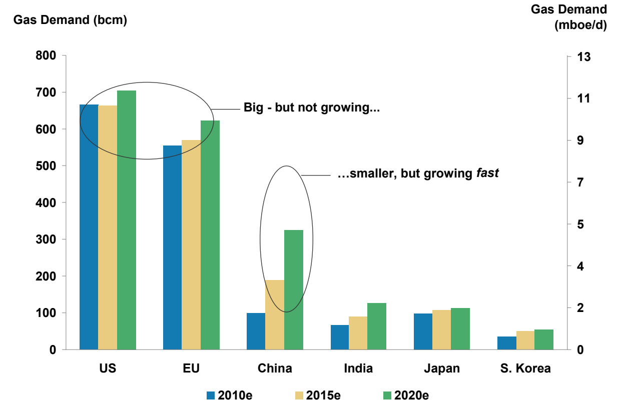
	Company	Rating*	Theme	Share Price (LC)	Price Target (LC)	Market Cap (US$ bn)	Free Float (%)
1.	InterOil	O	LT Infra shortage	70.1	135.0	3.2	80%
2.	Trina Solar	O	Green growth	24.2	33.5	1.9	88%
3.	CGG Veritas	O	China/India gas growth	24.7	33.0	5.2	90%
4.	GCL-Poly Energy	O	Green growth	3.7	4.8	7.4	61%
5.	Dow Chemical	O	Petchems Supercycle	36.8	48.0	43.0	100%
6.	Lyondell Basell	O	Petchems Supercycle	39.2	51.0	22.2	52%
7.	SBM Offshore	O	LT Infra shortage	18.5	24.0	3.8	99%
8.	Chevron Corporation	O	LT Infra shortage	99.9	126.0	201.3	100%
9.	Kunlun Energy	O	China/India gas growth	11.7	14.7	7.4	43%
10.	BG Group	O	LT Infra shortage	1460.0	1800.0	78.7	98%
11.	Reliance Industries	O	China/India gas growth	991.6	1206.0	72.0	52%
12.	Saipem	O	LT Infra shortage	35.9	43.0	22.2	54%
13.	Towngas China	O	China/India gas growth	3.9	4.7	1.0	25%
14.	Oil Search Ltd.	O	LT Infra shortage	6.6	7.7	8.8	84%
15.	Petronas Chemicals	O	Petchems Supercycle	6.6	7.6	17.3	31%
16.	CNOOC	O	China/India gas growth	17.7	20.0	100.5	36%
17.	Santos	O	LT Infra shortage	14.2	16.0	12.6	100%
18.	Gazprom	O	LT Infra shortage	29.2	32.0	172.1	45%
19.	ExxonMobil	EW	EU contract and vol risk	82.1	87.0	409.9	100%
20.	Eni SpA	U	EU contract and vol risk	17.5	18.0	88.0	57%
21.	CEZ	EW	EU gas and power price risk	809.0	830.0	25.0	29%
22.	RWE AG	U	EU contract and vol risk	47.9	47.0	35.5	78%
23.	E.ON	U	EU contract and vol risk	23.1	22.5	61.1	89%
24.	Statoil	U	EU contract and vol risk	148.3	140.0	84.5	33%
25.	Drax	U	EU gas and power price risk	396.3	310.0	2.3	99%



For valuation methodology and risks associated with any price targets above, please email morganstanley.research@morganstanley.com with a request for valuation methodology and risks on a particular stock.
Source: Morgan Stanley Research estimates

Exhibit 3

Global Gas Demand: China Is the Delta



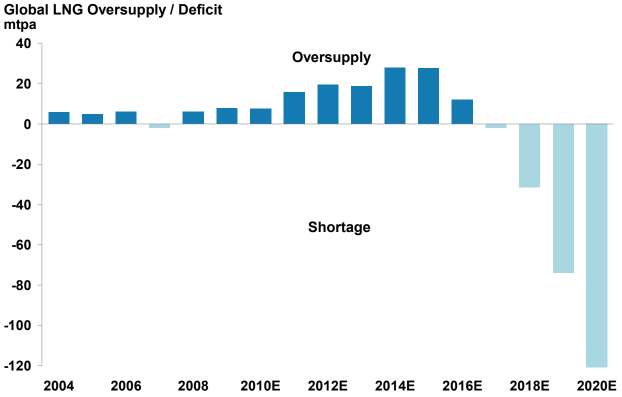
Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

3) **A significant global LNG oversupply will persist for five years.** There are many moving parts, but the key variable is that we expect China local gas production to continue to ramp up at a rate that will come close to meeting its demand growth. With no major change before 2015 in OECD countries' LNG demand, we believe the 2011 oversupply will persist until mid-decade.

4) **But then it all tightens. We are bullish after 2015.** After 2015, falling local production will dominate in Europe, and in China local gas production growth will eventually moderate. We forecast the world to be structurally short LNG after 2015 (exhibit 4).

Exhibit 4

Global LNG Oversupply to Stay High Until 2015



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (E)

Units, units …

The oil industry has a long, confusing history of using several different units to describe the same thing. For gas volumes we commonly see bcm (billion cubic meters) used in Europe, bcf or bcf/d (billion cubic feet per day) used in the US, and for LNG, mtpa (million tonnes per annum). In this report, we stay with bcm and mtpa, but for key numbers we also include the equivalent bcf/d. For reference, the key conversion factors are:

			...to		
	multiply by	**bcm**	**mtpa**	**bcf**	**mmscf/d**
	bcm	1	0.74	35.3	96.7
from...	**mtpa**	1.35	1	47.7	130.7
	bcf	0.028	0.0210	1	2.74
	mmscf/d	0.0103	0.0077	0.365	1

We acknowledge the contributions of Aditya Suresh to this report.

Global Stock Implications

We have extrapolated six key investment themes from our bottom-up analysis; these themes carry some clear implications for global gas stocks. We enumerate these themes and the stock implications below (exhibit 5).

Theme 1: China and India will satisfy burgeoning growth in local gas demand mostly from domestic production increases.

- **China National Offshore Oil Corp.** We reiterate our Overweight. CNOOC is set to benefit from its dominant China offshore shallow and deepwater acreage and gas production ramp-ups expected in 2013. Analyst: Wee-Kiat Tan.

- **Kunlun Energy and Towngas China.** We reiterate our Overweight on these two stocks. Both are well positioned to benefit from strongly rising Chinese gas demand and an associated infrastructure and customer base build-out. Analyst: Simon Lee.

- **Reliance.** We reiterate our Overweight. Reliance's position as the main operator of the Krishna-Godavari (KG) basin discoveries leaves it strongly placed to capture the upside on offer from robust local gas demand growth in India. Analyst: Vinay Jaising.

- **CGG Veritas.** We reiterate our Overweight. CGG owns Sercel, which is a key onshore seismic equipment manufacture with substantial exposure to onshore China seismic operations. Analyst: Martijn Rats.

Theme 2: After 2015, an LNG shortage would mean that major new liquefaction and trunk line projects would have to be awarded within two years.

- **Gazprom.** We reiterate our Overweight. We expect Gazprom's European piped gas volumes to be voluntarily restricted to 140-150bcm (13.6-14.5bcf/d) over the next few years as a direct consequence of the extended global LNG oversupply we forecast. While this is doubtless a near-term negative for Gazprom, we suggest that it is already more than reflected in Gazprom's low 2012 P/E of 5.0x (Morgan Stanley estimate). Of more importance, in our opinion, Gazprom is likely to be one the key direct beneficiaries of significant Chinese gas demand growth: We expect gas pricing terms to be agreed upon this year that effectively sanction two large Russia-China pipelines: the 30bcm Altai route into Western China and the 38bcm Eastern route. First gas is expected by 2015. Analyst: Matthew Thomas.

- **Chevron.** We reiterate our Overweight. With 24mtpa (15mtpa net) of liquefaction capacity currently under development in Australia, Chevron is the largest single developer in the world's largest growing source of LNG. Our bullish demand outlook post-2015 and abundant gas supply should support further expansions at Gorgon and Wheatstone. With 100% of its current LNG production under long-term contract, falling to 90% by 2015, Chevron is protected against near-term weakness in global gas pricing, a contrast to ExxonMobil (Equal-weight), which only has 58% of current volumes under long-term contract (70% in 2013). Analyst: Evan Calio.

- **InterOil.** We reiterate our Overweight. With one 3.0 mtpa liquefaction project under way in PNG and an expected 7.0 mtpa of additional capacity targeted through additional trains or FLNG, Interoil will strongly benefit from supply shortages and strong demand for LNG post-2015. Analyst: Evan Calio.

- Four of the top Australian exploration and production companies by market cap have substantial and increasing exposure to existing and planned developments in Australia and Papua New Guinea. Woodside (Equal-weight) and **Santos** (Overweight) are already significant producers relative to their size. **Oil Search** (Overweight) and Origin Energy (Underweight) will join mid-decade. For all, we expect volume growth and for oil-linked gas contracts to capture price potential. Woodside is the largest pure play, and Santos is the cheapest, in our view, in terms of discount to asset value. Analyst: Stuart Baker.

- **BG.** We reiterate our Overweight. BG is well placed in Australia to expand its current capacity plans and we expect material global gas price differentials to persist—a situation BG's portfolio is well positioned to exploit. Analyst: Theepan Jothilingam.

- A continued need for liquefaction and gas trunkline awards to address the post-2015 infrastructure shortage favours **Saipem** (Overweight)**.** An expected industry move towards floating LNG also favours **SBM Offshore** (Overweight). Analyst: Martijn Rats.

Theme 3: We see a US petrochemical supercycle based on gas oversupply pressure.

- **LyondellBasell and Dow Chemical.** We reiterate our Overweight on both companies. In line with our expectations for North America gas self-sufficiency to continue for the foreseeable future, our US Chemicals team expects the resulting wet gas NGLs to suppress ethane prices and for this to drive a US petrochemical supercycle. Analyst: Paul Mann.

- **Petronas Chemicals.** In addition to the US theme, Petronas Chemicals (Overweight) uses predominantly gas feedstock (especially butane and methane, which are largely market priced) for its crackers and so benefits more than its peers as spot prices come under pressure and as it is able to renegotiate more attractive gas contract terms in an oversupplied regional LNG market. Analyst: Vinay Jaising.

Theme 4. Green growth suppresses gas market share in power generation.

- In the clean energy sector, lower gas prices would ultimately reduce the cost competitiveness of renewable energy technologies like wind and solar energy, as compared with new combined cycle gas turbine (CCGT) capacity. However, despite this headwind, we still believe renewable energy growth is well supported by regulation and will remain strong through 2020. We favour low- cost players or technology leaders with scale as a way to play long-term renewable capacity growth. We reiterate our Overweight on **GCL-Poly Energy and Trina Solar.** Analyst: Sunil Gupta.

Theme 5: European gas contract and piped volume pressure.

- **Statoil.** We downgrade to Underweight; see our note *More Gas Blues Ahead – Double Downgrade to UW*, also published today. Unlike Gazprom, Statoil has no corresponding positive China-supply angle to offset the negative of what we believe will have to be restricted gas volumes into Europe for several years. Analyst: James Hubbard.

- **ENI.** We reiterate our Underweight. The gas and power segment (or, rather, the non-regulated gas marketing business) will remain under margin pressure until gas supply contracts are renegotiated, which, as highlighted in the Utilities section of this report, could take several years. Analyst: James Hubbard.

- Our views on oil and gas suggest that the oil-gas spread will persist, putting material pressure on the major midstream gas players **E.ON** (Underweight), **RWE** (Underweight), and **ENI** (Underweight), unless they can agree on material contract renegotiations. At best, this means a prolonged period of losses and uncertainty. There is considerable scope for downside surprises here. Analysts: Bobby Chada and James Hubbard.

- **ExxonMobil** (Equal-weight). With nearly 3.7 bcf/d of European natural gas production and 0.96 bcf/d of uncontracted LNG volumes (42% of global LNG portfolio), nearly 16% of ExxonMobil's global production is exposed to the near-term oversupply of global gas. While long-term growth in PNG and Australia will be supportive, we expect restricted gas volumes in Europe and weakness in spot LNG pricing to pressure the stock in the near term.

Theme 6: Weaker European gas prices to influence power prices too.

- In the utility sector, a lower spot European gas price and a lower contract gas formula price would imply lower power prices in most of Europe, with some notable exceptions, such as Italy. Surplus LNG over the longer term is also likely to keep conditions depressed in the Spanish market.

- This is bad news for most utilities that have material power price exposure. The most exposed names are **Drax**, **RWE**, **E.ON,** and **CEZ**. The weak global gas outlook is also a negative for global merchant power generators like **International Power**. Analyst: Bobby Chada.

Exhibit 5

Investment Themes and Affected Companies

Sector	Company	Analyst	Rating	Theme
Key Positive Themes				
1) China & India strong gas demand growth to be predominantly met from domestic production increases				
China Oil & Gas	CNOOC	Tan, Wee-Kiat	O	Growth from deepwater gas development
China Gas Distribution	Kunlun Energy	Lee, Simon	O	Local gas distribution infrastructure and customer base growth
China Gas Distribution	Towngas China	Chow, Vincent	O	
India Oil & Gas	Reliance	Jaising, Vinay	O	KG Basin production growth
Oil Services	CGG	Rats, Martijn	O	Gas infrastructure build-out
2) Post 2015 LNG shortage implies need for major near-term liquefaction and trunkline awards				
Russian Oil & Gas	Gazprom	Thomas, Matthew	O	30bcm Altai pipe sanction in 2011
Oil & Gas	BG	Jothilingam, Theepan	O	QCLNG train 3, global gas price arbitrage
Oil Services	Saipem	Rats, Martijn	O	Global liquefaction and gas trunkline build-out
Oil Services	SBM Offshore	Rats, Martijn	O	
Australia Oil & Gas	Santos	Baker, Stuart	O	Volume growth from high exposure to existing and planned developments in Australia and PNG
Australia Oil & Gas	Oil Search	Baker, Stuart	O	
Oil & Gas	Chevron	Calio, Evan	O	Global liquefaction build-out
Oil & Gas	InterOil	Calio, Evan	O	
3) Petchems Supercycle on the back of oversupply pressure on US and Asian spot gas prices				
US Chemicals	Lyondell Basell	Mann, Paul	O	Wet gas NGLs to suppress US ethane prices, spot Asian gas to come under pressure
US Chemicals	Dow Chemicals	Mann, Paul	O	
Malaysia Chemicals	Petronas Chemicals	Jaising, Vinay	O	
4) Green Energy growth suppressing gas market share upside in powergen				
China Clean Energy	GCL-Poly Energy	Gupta, Sunil	O	Renewables build-out for powergen
China Clean Energy	Trina Solar	Gupta, Sunil	O	
Key Negative Themes				
1) European contract & piped volume pressure				
Oil & Gas	Statoil	Hubbard, James	U	Production discipline in face of LNG oversupply
Oil & Gas	ENI	Hubbard, James	U	Gas marketing margin squeeze on oil inked input cost vs spot linked sales revenues
Utilities	RWE	Chada, Bobby	U	
Utilities	E.ON	Chada, Bobby	U	
Integrated Oil	ExxonMobil	Calio, Evan	EW	Restricted gas volumes in Europe to pressure the stock near-term
2) European gas and power prices				
Utilities	Drax	Ashworth, Nicholas	U	Weaker power prices
Utilities	RWE	Chada, Bobby	U	
Utilities	E.ON	Chada, Bobby	U	
Utilities	CEZ	Kuzmin, Igor	EW	

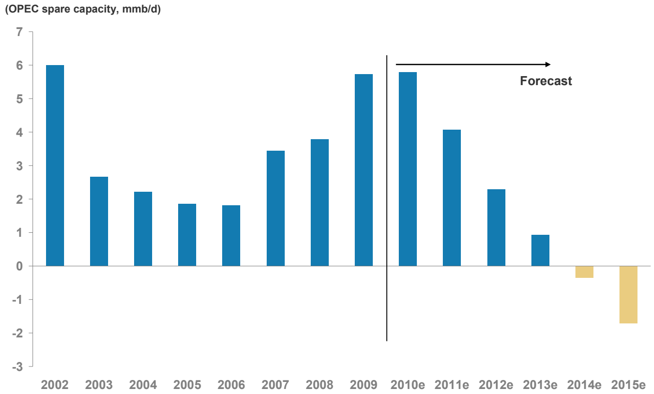
Source: Morgan Stanley Research

Gas World

Global energy demand is rising, and unless a wild card such as nuclear fusion comes to the rescue, fossil fuels look set to maintain their dominance for the next few decades. The mix, however, is expected to change. As oil markets continue to tighten, the received wisdom is that gas will inevitably gain market share: There is plenty of it left, it is in areas that are relatively more open to international oil company investment, and it is cleaner than coal or oil products (exhibit 6).

Exhibit 6

OPEC Oil Spare Capacity Is Set to Disappear by 2014

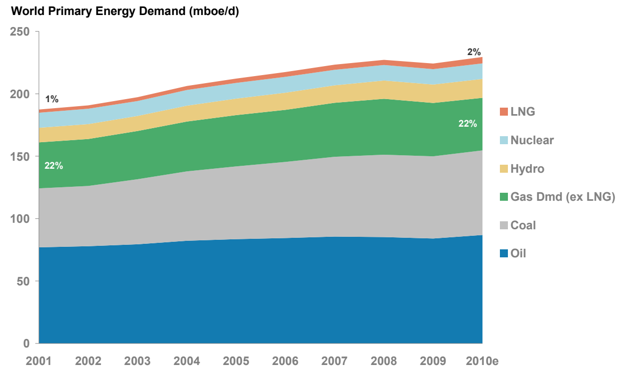


Source: IEA, Morgan Stanley Commodity Research estimates (e)

Gas accounts for roughly 22% of global energy consumption, compared to oil at 34% and LNG at only 2% (exhibit 7). LNG understandably commands great investor attention—it clearly has material growth potential into an increasingly oil-supply-challenged world.

Exhibit 7

Gas Accounts for 22% of Global Primary Energy Consumption



Source: BP Stat Review, Morgan Stanley Research estimates (e)

Middle East/North Africa unrest: No major impact as yet, but watch Algeria closely

So far, the only real impact on gas markets from recent MENA unrest have been the exports to Italy from Libya's Green Stream pipeline (9bcm), which has been shut down since late February. Egypt and Tunisia have continued to export LNG and piped gas without disruption throughout their own periods of unrest. The loss of Green Stream is unlikely to cause Italy a near-term problem given its current weak gas demand and the spare import capacity available from Austria, Switzerland, and regassification terminals. We expect Gazprom to be the immediate beneficiary.

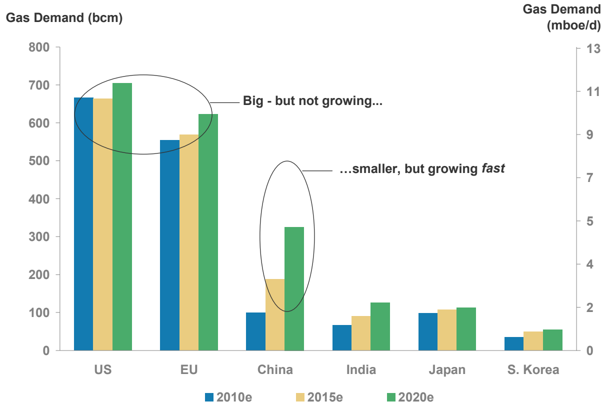
To date, Algeria has seen far less unrest than Libya, Egypt, or Tunisia. However, its mixed pipe and LNG exports (about 59bcm, or 5.7bcf/d) satisfy 10% of gas demand from EU35. Any sign of rising unrest in Algeria would justifiably cause concern for European gas buyers and would likely benefit both Gazprom and Statoil, as well as spot LNG cargoes.

Modelling Regional Gas Demand …

We have built bottom-up, regional gas demand forecasts by modelling the key drivers of residential, industrial, commercial, power generation, and transport gas demand. In power generation we take into account coal, nuclear, oil and gas new plants/retirements, as well as renewables construction plans.

Exhibit 8

Gas Demand: China Is the Delta, Whereas OECD Is Big but Stagnant



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

We discuss the regional gas demand outlooks in detail later in this report, but, in summary, we expect OECD nations to see close to stagnant gas demand and for the lion's share of global gas demand growth over the next 10 years to come from China, off a relatively low base as shown in exhibit 8.

- **Europe: Low growth to about 620bcm (60bcf/d).** We forecast gas demand to grow at a modest 1.2% CAGR to 2020, driving demand to about 620bcm (versus the Energy Information Administration estimate of 591bcm and the Cambridge Energy Research Associates estimate of 631bcm). We expect poor industrial demand growth and flat residential demand as efficiency improvements offset Eastern European home penetration growth; we also expect new renewables projects to meet most of the incremental power generation demand.

- **US: Modest demand growth from 666bcm to 705bcm (68bcf/d).** In the US, gas demand will rise moderately to 2020 on demand growth in the power generation segment, whilst we expect other segments to remain almost flat on 2010. Coal retirements in the generation stack (driven by environmental and other policy changes) and the degree to which gas captures share remain a key wildcard for demand.

- **China: A trebling in gas consumption, from 100bcm to more than 300bcm (29bcf/d) by 2020.** Gas demand will hit more than 300 bcm per year by 2020, driven by strong residential, commercial and industrial demand growth. Chinese power generation demand for gas will not be an important factor in gas demand, as coal and renewables dominate strategic investment plans in this segment.

- **India: Gas demand to nearly double to 126bcm (12bcf/d) from 66bcm by 2020.** India gas demand will reach 126bcm by 2020, as power generation and industrial demand rise strongly with India's GDP.

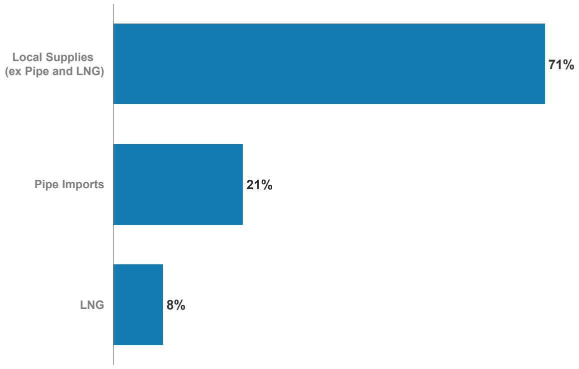
- **Japan, South Korea, and Taiwan: Steady growth of 5% CAGR from 140bcm to 220bcm (21.3bcf/d) by 2020.** We believe fuel switching remains an underlying support despite weak overall industrial and power generation demand.

… and Supply

The gas supply to meet the demand outlook summarised above will continue to come from three main sources: local gas production, imported pipeline gas, and imported liquefied gas. The vast majority of gas consumed in the world today, not surprisingly, is of the locally produced variety (exhibit 9).

Exhibit 9

Where Does Your Gas Come From? Most of the World's Gas Consumption Is Locally Produced



Source: BP Stat Review 2010

We model local gas production on a field-by-field basis (or basin-by-basin, in the case of China) and take a view on which planned import pipelines will actually go ahead (for example, in our base case we include Altai from Russia to China but exclude South Stream to Europe). After subtracting our local gas demand forecasts, we are left with an implied LNG demand, or indeed, a surplus in some cases. An implied surplus is only relevant if we believe that the country concerned will actually build liquefaction plants. Iran, for example, has huge LNG export potential, but any such plans have barely progressed over the last 10 years.

LNG, the Fuel of the Future …

Gas can potentially help fill our forecast global oil supply-demand gap, as it can partially substitute for oil in transport (for example, compressed natural gas and LNG for vehicles, and, longer term, potentially via power for electric cars). It may also substitute for oil in home heating and, in the petrochemical industry, as feedstock instead of naphtha.

However, gas faces some basic technical challenges. Not only is it more difficult to handle at the wellhead and in pre-transport processing (because a gas leak is so much more likely to be catastrophic than an oil leak), but the transport to end markets is also significantly more involved than it is for oil. Oil can be stored in simple tanks and then loaded into relatively simple ships for transport to any refinery or coastal import facility in the world. Gas, however, needs to travel either by pressurised pipelines to specific, inflexible destinations, or it needs to be liquefied (which involves cooling the gas down to around minus 162 degrees Centrigrade) and put on a specialised ship for transport. The reason it needs to be liquefied is that simply compressing gas molecules at room temperature gives a relatively low energy density—CNG (compressed natural gas) compresses gas molecules by about 200 times, as compared with LNG at about 600. Put another way, you need about three CNG ships to transport the same amount of energy that one LNG ship can handle.

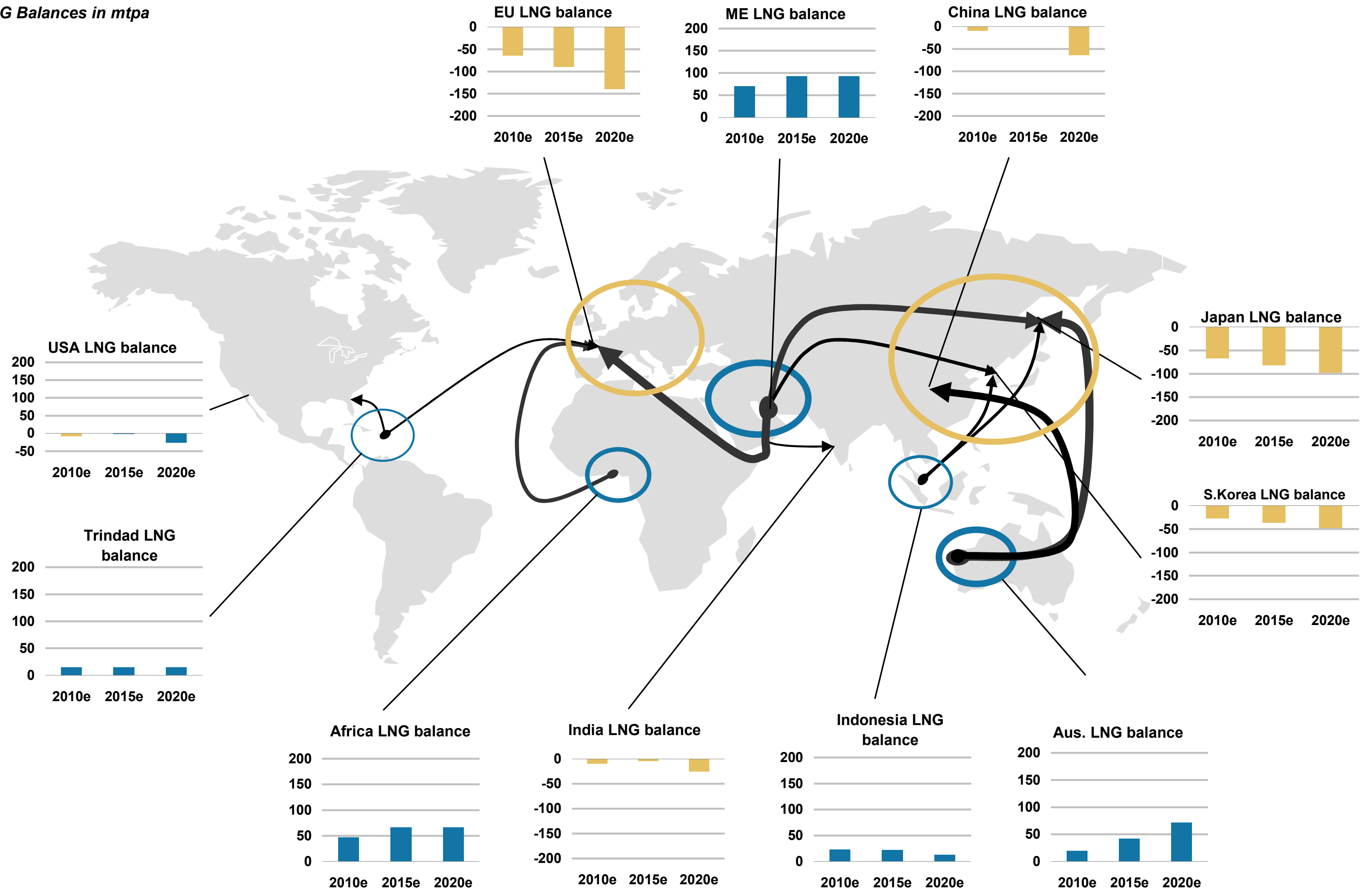
The global pattern of LNG flows is driven by the relative geography of deficit or surplus countries, and, of course, to what extent gas-rich countries have invested in liquefaction capacity in the past. The key LNG flows are shown in exhibit 10 and can be summarised as:

- The Middle East (Qatar, specifically) is the largest supplier and sends LNG to both Asia and Europe.
- Africa (Nigeria, Egypt, Algeria, and, soon, Angola) is also a major supplier of LNG to Europe.
- Indonesia and Australia both deliver LNG, mainly to Asia.
- On the supply side, the big change over the next 10 years will be Australia's emergence as a much more important exporter, with Asia (Japan, Korea, Taiwan, and China) the obvious preferred destination.
- The US has turned out to be largely self-sufficient.
- Japan and Europe are the two biggest consumers of LNG, but by 2020 China could be as important to LNG markets as Japan.

Exhibit 10

Major Typical Global LNG Flows and Balances

LNG Balances in mtpa



Source: Morgan Stanley Research estimates (e)

… but First We Face Years of Oversupply

In the long term, we agree with the thesis that gas will take share from oil, but today there are more bearish concerns – we have excess global LNG capacity, a US gas market that is structurally oversupplied (against expectations of only three years ago), and a European market facing an LNG import threat that is driving some major gas marketers to be loss-making. All of this raises important questions for investors, including:

- For how long will the global LNG glut last?
- Are European oil-linked gas contracts sustainable?
- Can China just soak up all excess LNG supply?
- Is investing in yet more liquefaction capacity the right decision for a company today?
- What might follow US unconventional gas and change the world of gas again in the next five years?
- Could the US become a material exporter of LNG?
- Will we ever see a “global gas price”?

To answer these questions we have built comprehensive global LNG supply and demand models with which we can analyse the impact of our base case assumptions and see the effect of flexing these key assumptions for various scenarios.

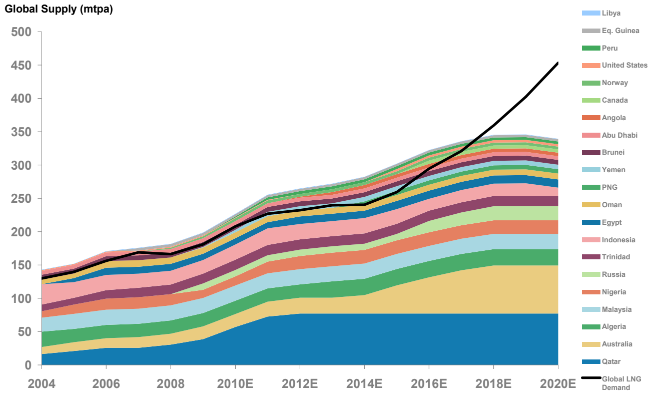
Global LNG Supply to Grow 30% by 2015

Qatar has been the main engine of liquefaction growth in recent years, but for the next decade it is Australia that will add by far the most new liquefaction capacity (exhibit 11). (Full details of the plants we include in our LNG supply model can be found in Appendix C.)

Our forecasts show global liquefaction capacity rising from 227mtpa in 2010 to 302mtpa in 2015, with the increase driven by projects under construction, committed, or largely contracted. The increase will carry over into 2016 and 2017 as well, as most of these mega-projects with multi-train production require one to two years to ramp up to full capacity (exhibit 12).

Exhibit 11

Global LNG Capacity: Australia to Emerge as the Second Largest Supplier, Behind Qatar



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (E)

- Australia will add 53mtpa to liquefaction capacity by 2020 from projects that are already committed or substantially contracted—and so will rival Qatar, in total capacity. In addition, the 6.6mtpa PNG LNG project in Papua New Guinea is under construction, with production expected in 2014.
- In 2011, new supply also expected from Qatar, with some small additions from Angola, Nigeria, and Algeria.
- There could be additional supply by 2020 from projects being conceived now but not yet sanctioned (not included in our base case); they could add about 200mtpa in total. Key sources of new supply in this list are Australia (more than 80mtpa), Iran (more than 40mtpa), and North America (more than 10mtpa).

Exhibit 12

Key LNG Capacity Additions by 2015

Country	Project	Company	Start Date	mtpa	Trains
Qatar	Qatargas 3 & 4 (train 6, 7)	QP, RD Shell, COP, Mitsui	2011	16	2
Australia	Gorgon 1-3	Chevron, Exxon, RD Shell	2015E	15	3
Australia	APLNG	Conoco, Origin, Sinopec	2015E	9	2
Australia	Wheatstone	Chevron, Apache, Kufpec, TEPCO	2016E	9	2
Australia	Gladstone-QCLNG	BG	2014E	9	2
Australia	Gladstone-GLNG	Santos, Total, Petronas	2015E	8	2
PNG	PNG LNG	Exxon, Oil Search, Santos	2014E	7	1
Angola	Soyo	Chevron, Sonangol, Total, BP, ENI	2012E	5	1
Algeria	Skikda	Sonatrach	2013E	5	1
Subtotal				**81**	**16**

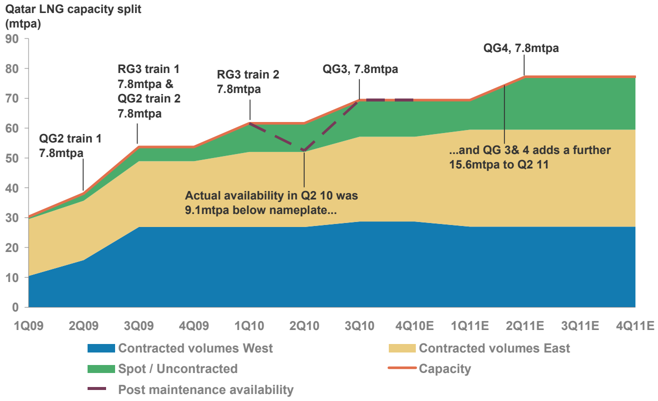
Source: Company data, Morgan Stanley Research estimates (E)

There Is Still a Near-term Threat from Qatar: Capacity Will Be *24mtpa higher* in Summer 2011

For the next 12 months, what strikes us is that many assume that the worst of the Qatari new supply threat is already over. In reality, not only is there still the 15.6mtpa of Qatargas 3 and 4 to come fully online in 2011, but around 9.1mtpa (on average) of capacity that was offline for unexpected maintenance last summer is set to be online this coming summer. The net effect is that Qatari LNG available capacity that was only 52.5mtpa in the summer of 2010 will be 76.5mtpa in summer 2011—an increase of 24mtpa year over year. This leads us to take a materially more bearish stance on global (and especially European) LNG supply/demand than most. Qatar can, of course, launch another unexpected maintenance program, but the point is that that is not currently the public plan, and, as such, a material supply threat currently exists (exhibit 13).

Exhibit 13

Qatar LNG Capacity: The Worst Is Yet to Come



Source: Morgan Stanley Research estimates

The potential Qatari supply overhang is a particular threat to European markets, in our opinion (exhibit 14). Qatar has consistently avoided selling any spot LNG cargoes into Asia, simply because to do so would undermine the oil-linked terms we believe that most, if not all, of its 30.7mtpa long-term contracted Asia supply enjoy. That leaves the US and Europe, at a time when European spot prices are $8.8/mmbtu, clearly more attractive than either last summer, when European prices were at least 25% lower than today, or the US Henry Hub price, which is currently trading at less than $4.0/mmbtu.

Recently Qatar announced a three year contract to sell LNG to Centrica. The LNG will be landed at the Grain LNG terminal in the UK, and is therefore presumably in addition to the volumes slated for the Milford Haven terminal. This shows, we think, some commitment to increasing European supply volumes.

Exhibit 14

Qatar to Sell Spot LNG Into Europe or Not?

Pros	Cons
1) EU spot gas prices are 25% higher than in 2010	1) Could drive an EU spot price collapse that speeds up a permanent regional transition from oil-linked contracts
2) Huge liquefaction capex is now a sunk cost that needs to be recouped	2) Risk of EU LNG re-exports finding their way to Asia on spot
3) Make decent returns on the NGL's even if EU spot prices collapse	3) From an NPV angle, it might be better to wait for the Chinese to sign long-term oil-linked contracts for same gas molecules
4) Can't sell spot East of Suez because will undermine bulk of oil-linked long-term contract portfolio	

Source: Morgan Stanley Research

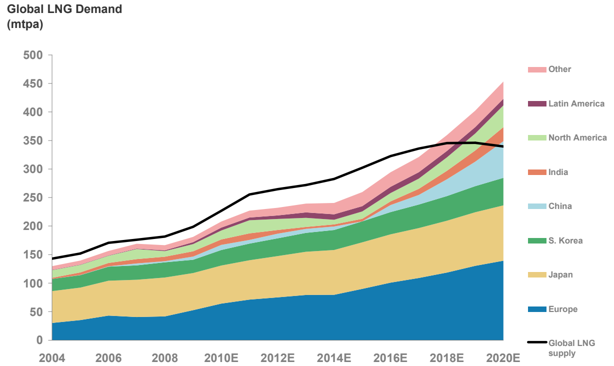
Global LNG Demand: Modest Growth Until 2015, Then an Acceleration

On the demand side, we model each region separately. We model the local production and pipeline imports and then offset this against bottom-up, local gas, demand-side analysis. The net result is an implied LNG demand (or in some scenarios, surplus) for these key areas.

As can be seen in exhibit 15, we do not expect global LNG demand to pick up materially before 2015, but from then we see strong growth in Europe (rising power generation demand/ falling local supplies) and China (rising residential and industrial demand and a post-2015 local production growth rate slowdown).

Exhibit 15

Global LNG Demand by Country: No Excitement Until After 2015, Then Europe and China Dominate

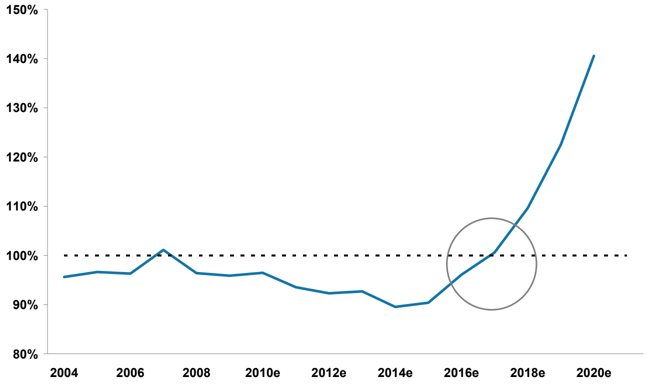


Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (E)

Assuming that liquefaction capacity is available 95% of the time on average (consistent with history), our supply/demand work implies that global liquefaction utilisation will remain at or below the 2010 level through to 2015. Those hoping for a recovery sooner than this are likely to be disappointed, in our view (exhibit 16).

Exhibit 16

Implied Global Liquefaction Capacity Utilization: Structurally Short by 2017



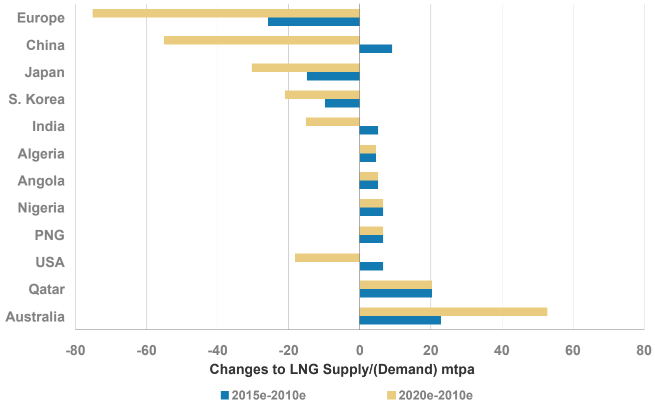
Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Despite our medium-term bearishness, there needs to be continued new liquefaction awards, in our view. If anything, the risk of complacency is rising; although we expect global LNG markets to remain loose for another five years, we then forecast a relatively swift tightening in supply/demand, to the extent that by 2017 we do not believe that currently planned liquefaction capacity will be capable of meeting global demand. We need to see announcements for new liquefaction capacity (and pipeline) over and above our base forecasts, and with typical project lifecycle of four years, we need to see these final investment decisions (FIDs) taken within the next 18-24 months. Our concern is that with global excess LNG capacity of close to 20% set to persist for several more years, few companies will be willing to push ahead with major liquefaction FIDs until it is too late to prevent a sharp post-2015 tightening.

Regarding the countries that we expect play the most important roles in *changing* the global LNG landscape over the next five to 10 years, in exhibit 17 we show that Australia dominates our forecasts on the supply side (and bear in mind that most of Qatar is already on-stream).

Exhibit 17

Changing LNG Supply/Demand: Europe, China, and Australia Matter Most



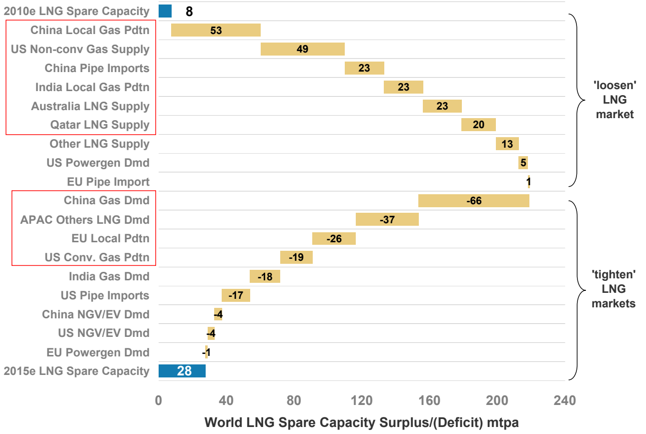
Source: WMAC, Morgan Stanley Research estimates (e)

On the demand side, China and Europe are set to see material increases, as declines in indigenous production coincide with higher demand, particularly in 2015-2020.

We show the key expected changes in underlying LNG market drivers out to 2015 in exhibit 18, where the key moving parts of increased US unconventional gas production, Chinese production, China pipe imports, and Qatar/Australia LNG capacity are almost entirely offset by strong Chinese gas demand growth and US conventional gas production declines.

Exhibit 18

How We Expect the Global LNG Surplus Will Evolve (Base Case), 2010e-15e

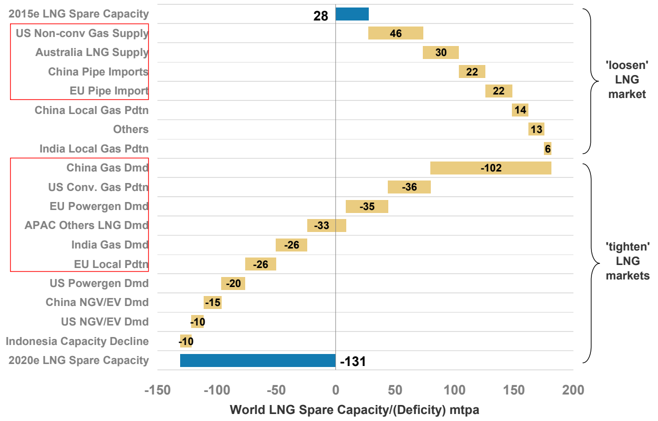


Source: Morgan Stanley Research estimates

After 2015, we forecast the dynamics to change; US unconventional gas production growth should still be a feature, as will new Australian liquefaction capacity and higher pipe imports to China, but we expect that Chinese local production increases will become less material (exhibit 19). In our base case these LNG market “looseners” will be more than offset by the combination of continued strong growth in Chinese (and to a lesser extent Indian) gas demand, European and US conventional production declines, and rising European power generation demand.

Exhibit 19

How We Expect the Global LNG Surplus Will Evolve (Base Case), 2015e-20e



Source: Morgan Stanley Research estimates

Scenarios, Scenarios

We ran various scenarios to establish which factors have the greatest impact on our forecast global LNG balance. The potential list of issues that could affect the LNG supply/demand outlook is long, so we chose to focus on GDP, renewables construction, pipeline construction, conventional and unconventional gas production, Australia liquefaction capacity, and the potential impact of electric and natural gas vehicles (exhibit 20).

Exhibit 20

Fourteen Scenarios Modelled

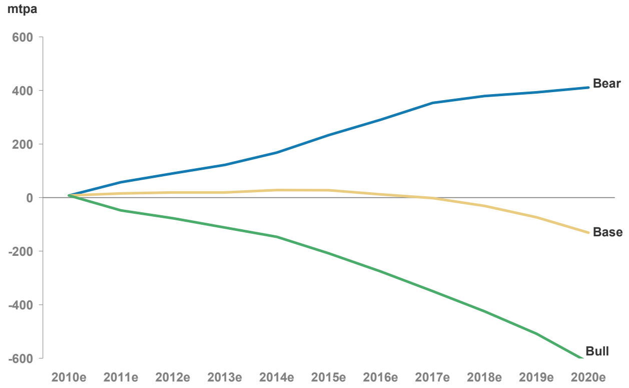
Scenario	Base	Bear	Bull
EU LNG Scenarios			
1. EU GDP Growth	2.1% LT GDP Growth	0.25% LT GDP growth	3.6% LT GDP growth
2. EU Pipe Imports	Nord Stream (28bcm) comes online by 2012. No Nabucco (31bcm) and South Stream (63bcm).	Nord Stream online by 2012, Nabucco by 2015, South Stream steady ramp up from 2016	More Supply Discipline. No Nabucco and South Stream. Nord Stream comes online by 2012.
3. EU Renewables Build-Out	**250GW** of renewables capacity built between 2010-20. Gas market share in **powergen** increases slightly to 26% in 2020 from 24% in 2010.	**300GW** of renewables capacity built between 2010-20. Gas market share in **powergen** stays flat at ~24% till 2020.	**60GW** of renewables capacity built between 2010-20. Gas market share in **powergen** increases to 35% in 2020 from 24% in 2010.
China LNG Scenarios			
4. China GDP Demand	8% LT GDP growth. Energy mix in powergen consistent with Chinese 2020 strategic energy plan	5.5% LT GDP growth, lack of powergen substitution	10.5% LT GDP growth, faster coal substitution in powergen
5. China Pipe Imports	30bcm Russia, 30bcm Kaz/Turk, 4bcm Myanmar	60bcm Russia, 60bcm Kaz/Turk, 4bcm Myanmar	0bcm Russia, 20bcm Kaz/Turk, 4bcm Myanmar
6. China Local Gas Supply	China local gas production **increases 90bcm to reach 175bcm by 2020**	Company's aggressive pdtn targets achieved. Local gas pdtn **increases 175bcm to reach ~260bcm by 2020.**	-25% vs. base
7. China NGV Demand	5% new vehicle penetration by 2020	0.5% new vehicle penetration by	15% new vehicle penetration by 2020
8. China EV Demand	10% new LV sales to be EV by 2020	No material uptake	50% new LV sales to be EV by 2020
US LNG Scenarios			
9. US GDP Growth	2.6% LT GDP growth	1.1% LT GDP growth	4.1% LT GDP growth
10. US Gas Supply	45bcm increase in local gas pdtn to ~635bcm by 2020. Non-conventional pdtn growth offset to some extent by underlying conventional declines.	20% higher non-conventional pdtn and 10% higher conventional by 2020	20% lower non-conventional pdtn and 10% lower conventional by 2020
11. US Renewables Build-Out	**160GW** of renewables capacity built between 2010-20. Gas market share in **powergen** declines to 23% in 2020 from 25% in 2010.	**200GW** of renewables capacity built between 2010-20. Gas market share in **powergen** declines to 20% in 2020 from 25% in 2010.	**120GW** of renewables capacity built between 2010-20. Gas market share in **powergen** increases to 26% in 2020 from 25% in 2010.
12. US NGV Demand	10% LDV, 5% HDV of new vehicle sales to be NGV by 2020	0% LDV, 0.5% HDV of new vehicle sales to be NGV by 2020	25% LDV, 10% HDV of new vehicle sales to be NGV by 2020
13. US EV Demand	10% new LV sales to be EV by 2020 - exponential increase from 2012	No material uptake	50% new LV sales to be EV by 2020 - exponential increase from 2012
Australia LNG Supply			
14. New Liquefaction plants	Base (Existing + Under Const.) LNG capacity: 72mtpa by 2020 (from 19 mtpa 2010)	All LNG projects go ahead (unrisked capacity): 156mtpa by 2020 (from 19 mtpa 2010)	Major project delays - Gorgon, QCLNG, GLNG, Wheatstone 3 yr delay: 65mtpa by 2020 (from 19 mtpa 2010)

Source: Morgan Stanley Research estimates

We aggregated all the bull, bear, and base scenarios into three global LNG surplus/(deficit) outlooks and present them in exhibit 21, where we see a very wide range of possible outcomes.

Exhibit 21

Global LNG Surplus/(Deficit) Scenarios: A Wide Range Around Our Base Case



Source: WMAC, BP Stat Review, Morgan Stanley Research estimates (e)

The wide range of possible outcomes is inevitable given the breadth of scenarios we consider. But if we look in more detail at what the most important issues are, we see from our 2015 scenario work (exhibits 22 and 23) that, in order of importance, the most significant factors are:

- **European GDP,** because economic growth and industrial production are prime drivers of incremental power demand, which will be at least partially met by CCGTs.

- **US unconventional gas production.** Given the rapid production increase in US unconventional gas in recent years (83bcm, or 8bcf/d; 14% of total demand since 2000) against threats from environmental challengers, there is clearly a wide range of growth rates possible over the next decade.

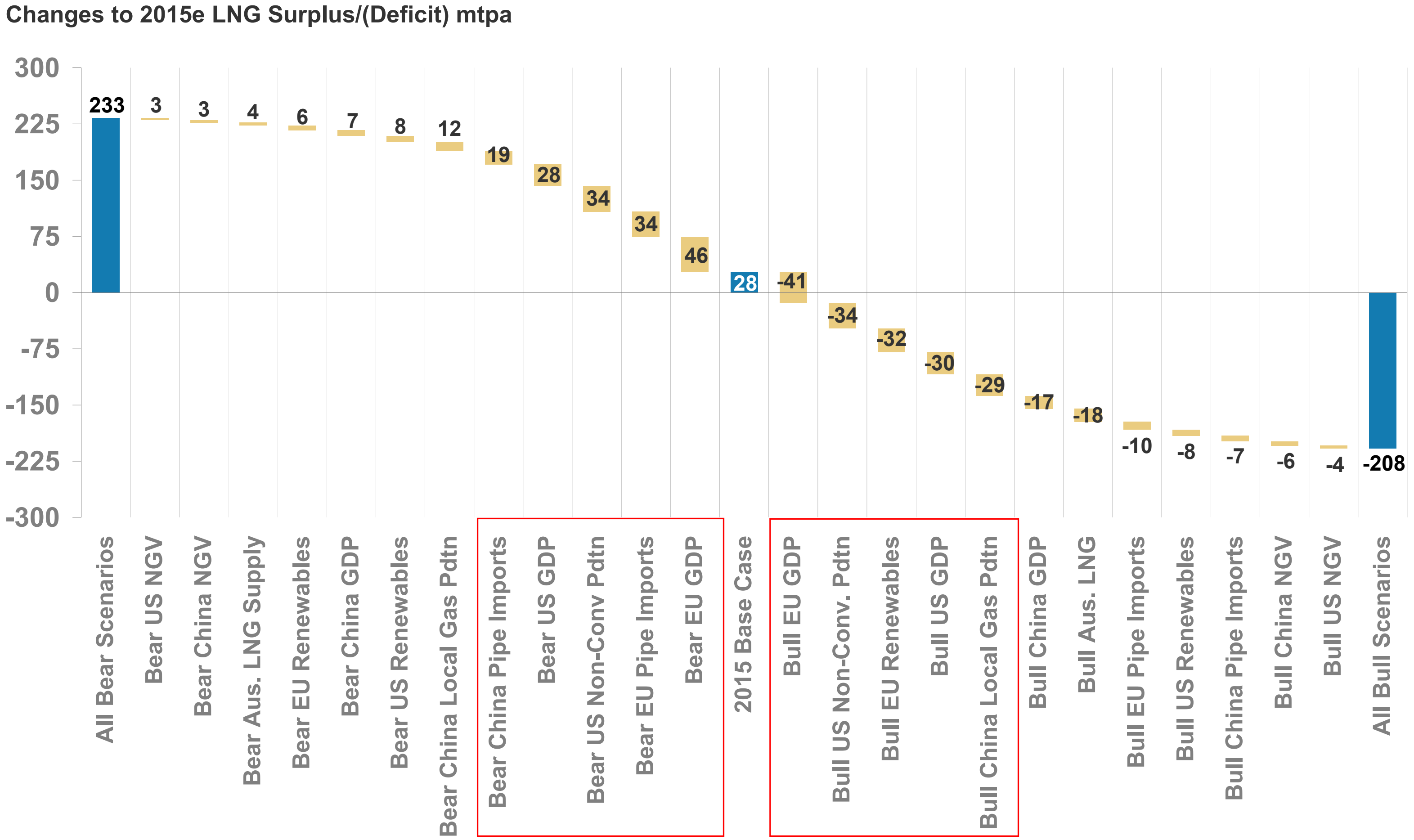
- **US GDP,** for the same reason as Europe above.

- **China new pipelines.** The long-delayed Altai pipeline from Russia is moving closer to sanction (planned for 2011) and could add 30bcm (2.9bcf/d) into Western China by 2015. We assume it does so in our base case. The Eastern route could add another 30bcm, but given that there is no firm FID date, we only include this as a bear case scenario for now.

- **European renewables capacity.** Aggressive solar and wind power generation construction is already displacing about 200TWh (an implied 42bcm or 4.1bcf/d) of 2015 gas demand in our European power generation model. If oil and gas prices rise further and CO_2 targets are adhered to, there is still material upside to solar and wind construction and, as a result, downside to European gas consumption.

Exhibit 22

Global LNG Surplus/(Deficit) – Bull-Bear-Base Waterfall 2015e – GDP, US Unconventional Gas and Renewables Rollout Assumption Matter the Most



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

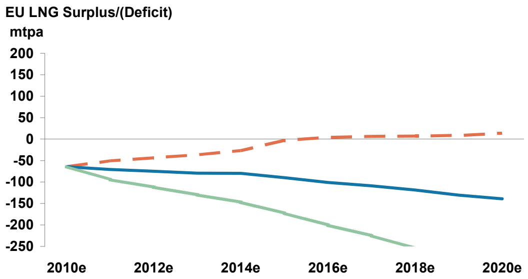
Exhibit 23

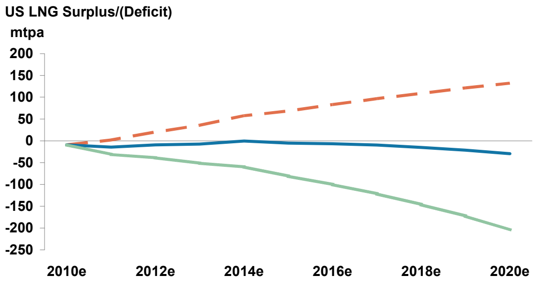
Regional/Global LNG Supply/Demand Balance Outlook: Bull-Bear-Base Scenarios

EU Base: Flat LNG demand till 2015
- LT GDP growth 2.1%
- 250GW of additional renewables capacity by 2020.

- Key swing factors are GDP, new pipe supplies and renewables construction.

- Bear case of implied net LNG exports is extremely unlikely in reality.





US Base: Little need for LNG for the next five years.
- LT GDP growth 2.6%
- Renewables to take powergen share from gas and coal.

- Key swing factors are GDP and shale production.

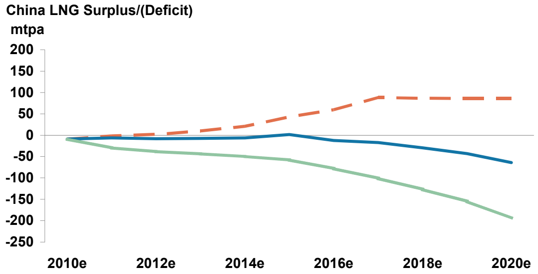
- Bear case of implied LNG exports would need immense liquefaction construction.

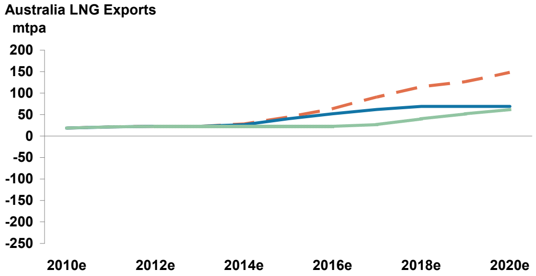
– – MS Bear Case — MS Base Case — MS Bull Case

China Base: Flat to 2015 then rapidily growing LNG demand.
- LT growth 8%
- Turkmenistan 30bcm.
- Local production growth of 8% p.a. to 2015.

- Key swing factors are local production (incl shale), GDP, coal & renewables.

- Bear case of LNG exports very unlikely.





Australia Base: an extra 53mtpa supply by 2020 vs. 2010

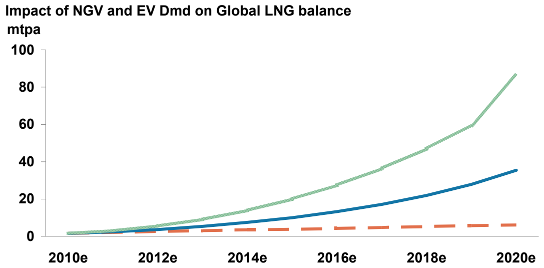
- Key Projects: Gorgon (15mtpa), APLNG (9mtpa), Wheatstone (9mtpa), QCLNG (9mtpa), GLNG (8mtpa)

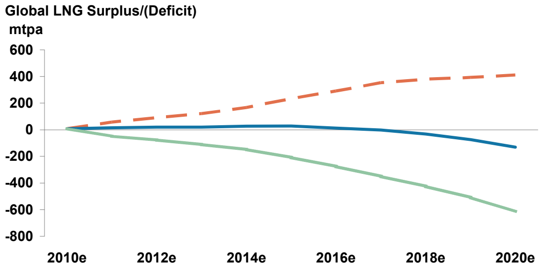
- An extra 84mtpa is possible (on top of 53mtpa base) in an unrisked case.

– – MS Bear Case — MS Base Case — MS Bull Case

-NGV Base: US 7% of new vehicle sales by 2020, China 5% of new vehicle sales.

-EV Base: Immaterial impact on global gas balances even if we assume 50% new vehicle penetration rates by 2020.





Global Base: Oversupply till 2016 then rapid tightening.

Top 5 Game Changers -

a) GDP assumptions (powergen dmd)
b) US shale gas
c) Renewables build-out
d) Australia LNG capacity
e) Pipe Imports in EU and China

Source: WMAC, BP Stat Review, Morgan Stanley Research estimates (e)

Global Gas

Impact on Related Industries

European Utilities: Gas to Drag ... and Drag

Bobby Chada
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Do a rising oil price and strong Asian demand for gas mean that global gas prices will rally quickly and power prices will follow suit?

We believe that even with a higher oil price and strong economic growth, gas prices in Europe will likely fall, not rise, due to the oversupply for the period before 2016. We feel that the market understates the importance that renewable energy and domestic gas production in China and India have on global gas demand.

Given that gas is a key input cost for the marginal electricity generating plant, this oversupply will have a negative effect on wholesale power prices in most parts of Europe. We therefore believe that hopes of a speedy power price recovery are overdone. In addition, our analysis suggests that power markets are just as oversupplied as the gas market, if not more so.

Will oil and gas prices recouple, providing a dramatic turnaround in midstream gas profits for many utilities?

Given our view on a "decade of two halves", we do not believe that the oil-gas spread (i.e., the decoupling of the hub-based gas prices from oil price-linked contract gas prices) will recouple in the near term. Recoupling depends on (1) the speed of the gas market rebound, which we calculate will not happen until 2016, and (2) the degree to which major gas producers renegotiate long-term contracts, which we feel will take at least 12 months (these renegotiations may require more than one round to fix the contract structures properly).

Thus, we continue to expect midstream gas losses to plague the utilities with midstream gas businesses. In particular this is an issue for E.ON, RWE, Edison, Gas Natural, and GDF Suez. However, we note that GDF Suez's exposure is not as big as it looks because of its large French retail business, which, for now at least, is protected.

Best positioned: Enel, Centrica, EDF.

Potentially challenged: Drax, E.ON, RWE, Gas Natural, Iberdrola, GDF Suez.

Increasingly, the market seems to take the view that strong Asia growth, well-organized gas producer behaviour, and the high oil price means that gas prices will rise, and with them, power prices.

We disagree. Our analysis shows that the global LNG market and the EU gas market will be oversupplied until 2016, which should mean weak gas prices. This, coupled with oversupplied EU power markets, means prospects of a power price recovery are bleak, we think.

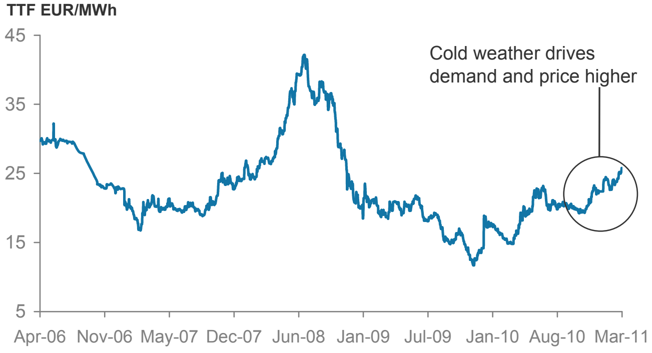
The "Decade of Two Halves" Means Mid-Term EU Gas Prices Are Likely to Fall …

The results of our global gas supply-demand analysis suggest that global spare LNG capacity will rise again in 2011 and that significant LNG overcapacity is likely to persist for five years. Therefore, we do not believe that the European gas market will become tight—or "short"—gas or LNG until 2016.

We think that the main way in which our thesis differs from consensus is in its holistic global approach, where we involve our regional energy and utility specialists to get a view on gas supply and demand along the value chain. This approach has produced a few surprises along the way: Specifically, we expect renewables to cannibalise gas demand in power generation in Europe, and we also foresee higher-than-consensus domestic gas production in China and India, offsetting much of the demand growth there in the next five years. We also see strong medium-term liquefaction capacity growth in Australia and have a differentiated view on the near-term capacity threat still posed by Qatar.

Exhibit 24

European Spot Gas Prices Have Rebounded Sharply



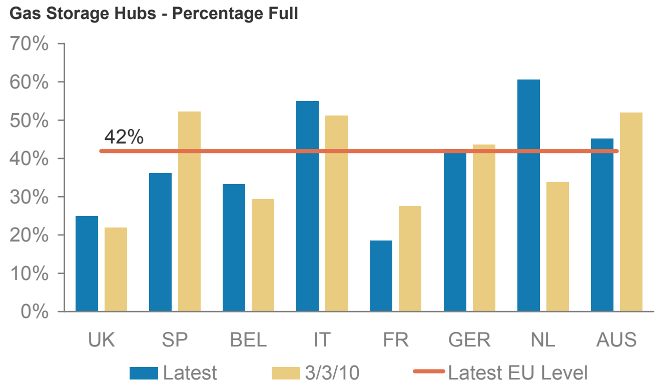
Source: Bloomberg

In the last six months EU gas prices have rallied due to cold weather, which enhanced gas demand in 2010 by as much as 10% (exhibit 24). This seasonal effect should unwind, as weather in 2011 has been much more normal. Storage levels are already normalizing (exhibits 25 and 26).

If our thesis on continued oversupply of gas is correct, it seems logical that gas prices—and to be clear, by this we mean hub-based gas prices—will decline. At the same time, it is perfectly possible that high oil prices will continue to push up long-term contract (LTC) gas prices. This thesis has a number of implications for the European utility sector.

Exhibit 25

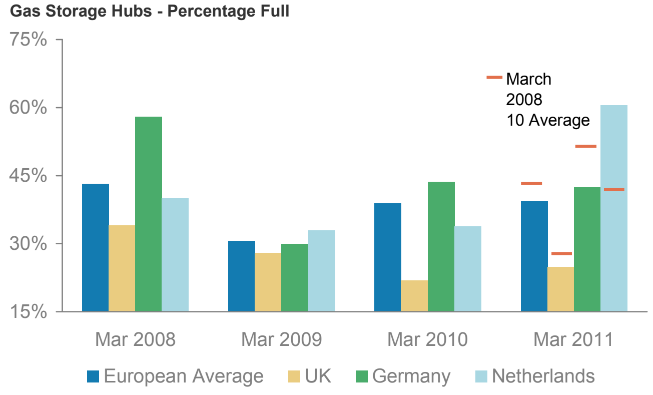
European Gas Storage Levels Are Lower Than in 2010 in Many Countries …



Source: GIE, Morgan Stanley Research

Exhibit 26

… and Are Now Below Historical Average Levels in the UK and Germany, but In Line, on Average



Source: GIE, Morgan Stanley Research

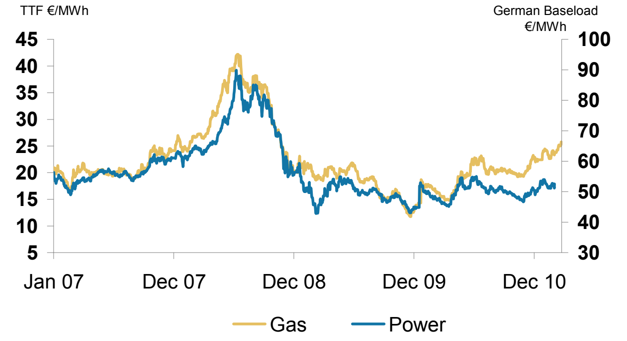
Gas Prices Are a Major Driver of EU Power Prices

In most European wholesale power markets, hub-based gas prices are one of the major drivers of power prices (exhibits 27 and 28). Of course, there are others—coal prices, supply-demand balance, carbon prices, and weather, for example—but the fact remains that if gas prices do decline it is hard to see power prices and generation spreads rallying in any meaningful way. Rather, we would expect further downside.

The importance of gas on power price-setting plants differs region by region. At one extreme, we believe spot gas prices influence power prices very directly in the UK and, to a similar extent, in Spain. Lower gas prices would therefore be bearish for power prices in both these markets.

Exhibit 27

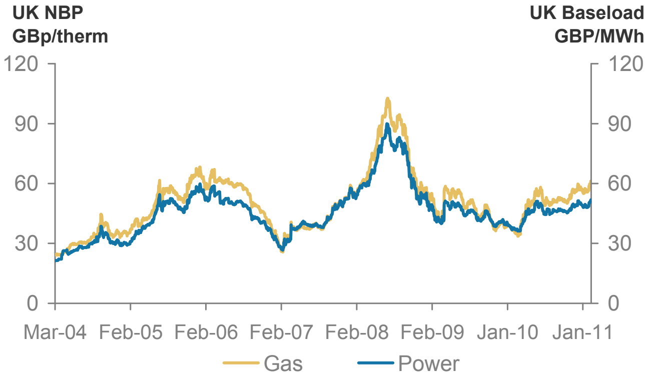
German Power Prices Are Highly Correlated to Gas Price Changes …



Source: Bloomberg

Exhibit 28

… and UK Power Prices Are Even More Highly Correlated With Gas Prices



Source: Bloomberg

Exhibit 29

Different Regional Power Markets Have Varying Exposure to Gas and to Spot Versus LTC Gas Pricing for the Marginal Generating Plants

Region	Predominant Marginal Plant	Spot or LTC Gas Basis
Germany	Coal and Gas	Spot
UK	Gas	Spot
Spain	Gas	Spot
Italy	Gas	LTC
Netherlands	Gas	Spot

Source: Morgan Stanley Research

At the other extreme we believe that although Italy has a lot of gas-fired plants that operate at the margin, these plants typically use gas under LTCs and thus spot gas prices have much less effect on the Italian market; oil prices, which drive the LTC price, are much more important.

And, in between these extremes, we estimate that gas-fired power plants in Germany now set the price in about half of the hours. Lower gas prices will therefore mean lower power prices as (1) an increasing number of power stations burn spot gas, and (2) a big oil-gas spread leads to long-term gas contract prices that will likely be negotiated down over the next few years.

Exhibit 29 shows the influence of gas plants and the different types of gas contract in the different regional markets.

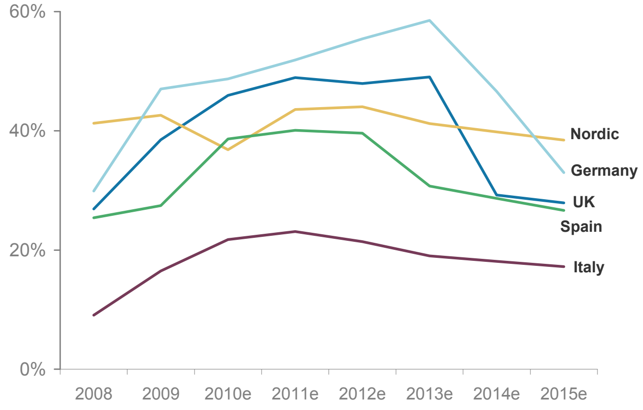
Don’t Forget the Oversupply in Power: It Is a Long, Long Cycle

Another factor behind our negative view on power prices is that we see the power markets as substantially oversupplied, and we believe that capacity closures are needed to ensure that the markets move back into balance (exhibit 30). But, we believe it will take a long time for these capacity closures to come through, and therefore it is far too early to be bullish on a power price recovery. This is a long cycle and we may well bounce along the bottom for an extended period.

Again, not all markets are equal. For example, we believe that forced power plant closures in the UK (under the EU Large Combustion Plant Directive) may bring about a market recovery sooner than in the German market. And in the Italian market, the structure of the gas market, because it remains largely LTC-based, will mean that power prices will be higher than in the rest of Europe and coal and hydro plants will earn very attractive margins.

Exhibit 30

European Reserve Margins: Power Markets Appear Very Oversupplied



Source: Morgan Stanley Research

But we remain very cautious on the outlook for the wider Central European power market (Germany and the related coutries—Austria, Belgium, Holland, Switzerland, etc.). Here we think that capacity closures are critical, but it is likely to take much longer than consensus expects for these closures to happen.

The speed at which the cycle turns in the wider Central European market is going to be very dependent—indeed almost wholly dependent—on the speed at which capacity is retired. We believe it inevitable that plants will be closed, but again, at a protracted rate.

It is important to highlight that simply closing very old, very inefficient facilities that are now hardly ever running (like oil plants or old and inflexible coal plants) will not make much, if any, difference to the market. Rather, to have an impact, the plants that must be retired must be “in merit” and running. Someone, in other words, has to close profitable plants in order to move the market. We calculate that around 25GW of capacity will have to be closed in Germany alone to tighten the market fully. To put this in context, in the last generation downturn in Germany, only about 12GW of capacity was closed.

Why are we bearish on the length of the cycle?

(1) Not all players in the market behave rationally all of the time, and many smaller or municipally owned players have objectives that are very different from those of larger, more economically orientated players.

(2) It is a tough decision to close plants that are running and are profitable as part of a portfolio, even if barely so.

(3) It is not so easy to close capacity. Because of local job losses, shutting down plants can lead to difficult situations with staff, union, political, and municipal stakeholders.

(4) Energy trading adds value to power plants and vice versa. The advanced energy trading functions of large utilities mean that they capture both the intrinsic value (the dark green spread) and €5-10/MWh of extrinsic value (the option value of trading around this physical position). If we make an allowance for this, in addition to the portfolio effects, then the decision to close may not be so straightforward.

EU Energy Policy: The Elephant in the Room?

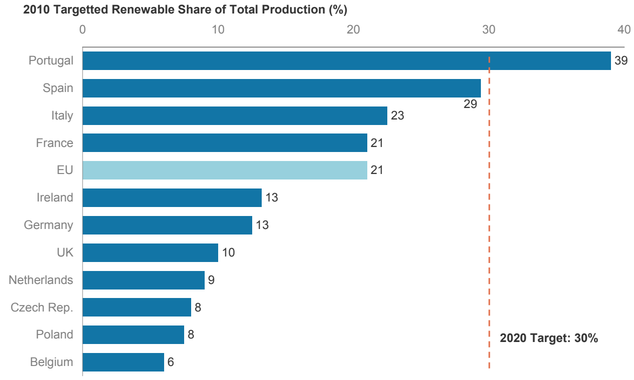
Every EU member state government has stretching targets for the proportion of energy and electricity to be sourced from renewable sources. We expect them to remain committed to these. Although some governments have changed the subsidies, it is generally because they were adding renewables in line with or ahead of targets. We believe there is increasing evidence of governments using subsidies to manage renewable capacity additions and some are even attempting to increase targets.

This will lead to targets for significant increases in renewables capacity, especially wind and solar, over the next five years. At current growth rates, the EC Joint Research Council calculates that renewables will make up 40% of electricity generation by 2020 (exhibit 31). Renewable capacity additions were 17GW in 2009 (versus 14 GW in 2008). This represented 62% of total capacity additions (versus 58% in 2008). The 2010 data are not fully officially released yet, but it looks set to be even greater than 2009 capacity additions.

This is critical for our analysis of the gas and power markets. First, it is a critical part of our assumption on gas demand in Europe: more renewable generation means a smaller requirement for gas-fired generation and thus less gas demand. And second, just as pertinent to utilities, the increase in renewable generation implies material losses in traditional utility power generation market share in many markets, as it is cannibalised by renewables.

Exhibit 31

Most EU Member States Need to Increase Significantly Renewable Electricity Generation from 2010 to 2020 in Order to Meet the Average 2020 Target



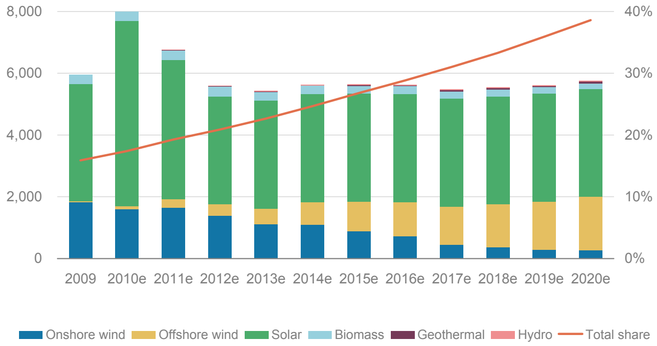
Source: European Commission (Note: Only selected member states shown)

This loss of market share may be partly offset by the benefits of more volatile power prices, but if decent renewables are readily available, which should be the case on average, this availability could also put downward pressure on average wholesale power prices. These are negative trends for utilities because they cannibalise the traditional profit base, which means lower terminal profits.

We see downside to volumes sold for three reasons: the lower demand outlook, the cannibalisation of traditional utility generation volumes by renewables, and increased energy efficiency. The UK is a prime example of this in action, and German government policy, if implemented, could be even worse from a utility perspective (exhibit 32). In the medium term, we do not see government commitment to renewables wavering, and solar is starting to concern us as a volume threat in some markets.

Exhibit 32

German Government Targets Imply Annual Installations Stay At 6-8GW per Year Through 2010



e = Federal Environment Ministry (BMU) estimates Source: Federal Environment Ministry (BMU), Morgan Stanley Research

Will oil and gas prices recouple, providing a dramatic turnaround in midstream gas profits for many utilities?
The market seems to hope for a speedy resolution to the oil-gas spread and the losses that this is crystallizing for the midstream gas player, which include some of the big utilities.

We disagree. We believe that the gas contract renegotiations, while they will ultimately be successful, will be long, drawn-out affairs and that the success rate may not be as high as some hope. Neither do we rule out that it may take more than one contract round to get the renegotiations settled finally.

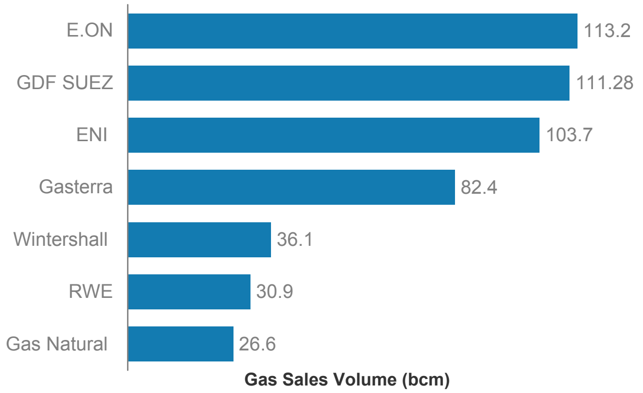
Midstream gas business model under pressure
Exhibit 33 shows the biggest midstream gas players in Europe—clearly many of these are large, integrated utilities. These midstream businesses are being put under a lot of pressure from the nature of their business model, which was set up decades ago to serve a very different market. Back

then there was no spot market, and midstream companies offered the only real route to market.

Around 70% of the gas that is imported into continental Europe does so under long-term indexed gas contracts. These supply pre-arranged volumes of gas at prices indexed mainly to oil-based products (historically, 98% are linked to oil-based products). The contracts have triennial renegotiations, but these are very long-term in nature and are “take or pay” in style, with minimum take levels.

Exhibit 33

Europe’s Largest Midstream Gas Players



Source: Company data

Essentially, the midstream gas business involves buying gas under LTCs from major producing countries like Russia, Norway, and Holland. The LTCs have historically been indexed to a basket of crude oil-based products, although the last round of renegotiations (the 2009-2010 round) saw this basket start to include more spot gas (around 15-17%, we believe). Midstream companies then store, optimize (that is, trade around the physical position to take advantage of arbitrage opportunities) and distribute this gas to end customers (industrial and commercial customers, power generators, and resellers). Historically, the midstream companies also have sold the gas to end customers at oil-linked prices, but since the development of the spot markets, this has now changed, with most customers demanding prices based off hub gas prices.

The Oil-Gas Spread Is Widening Again

The problem is that the current oil-gas spread—the difference between the oil-linked contract price in the LTCs and the spot price that customers now demand—is material and is a negative for the midstream gas companies (exhibit 34).

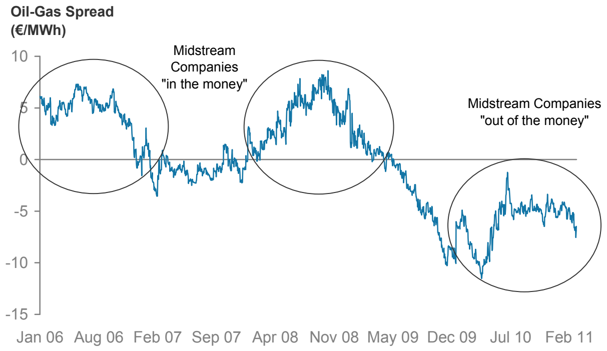
Contract Renegotiations Will Be Critical

Many of the large buyers of gas under LTCs have approached the gas producers to ask for material changes in the structure of the contracts to try to eradicate the gap between the LTC price and the spot gas price and to alter the burden of risk.

We do not believe that these renegotiations will be easy, given that the utilities have been on the right side of these contracts for large periods of the last five years. Without renegotiation there is some meaningful earnings risk for the sector.

Exhibit 34

The Oil-Gas Spread Is Widening Again: A Material Pressure for the Midstream Companies

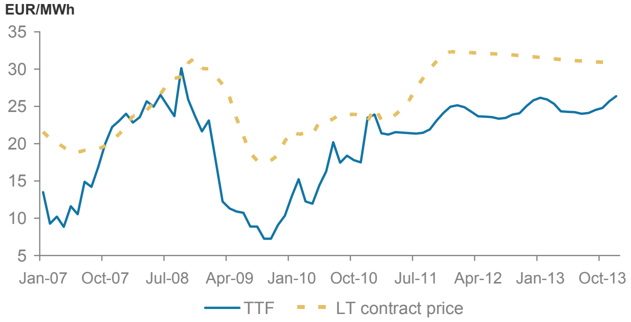


Source: Bloomberg, Morgan Stanley Research

E.ON, and RWE and GDF Suez have again made it clear that with the current state of the gas market they will face losses unless their LTCs are renegotiated. This time the issue is not a take-or-pay crisis, but the fact that the purchase price in the LTCs is well above the price that customers are willing to pay. Midstream players could therefore be forced to endure losses, cede market share, or exit a business that has been very profitable over the years. What is worse, the forward curves do not suggest that the oil and gas markets will recouple anytime soon (exhibit 35).

Exhibit 35

Border Gas Forecast Versus Hub Prices: Oil and Gas Prices Will Not Recouple Before 2013



Source: Bloomberg, Morgan Stanley Research

Conclusion: Contract Renegotiations Will Not Be Easy or Fast

We believe that another period of uncertainty—and lower profits—may persist, as most long-term gas contracts must be renegotiated if the utilities are to avoid incurring some big losses under current market conditions. From the other side, however, the midstream players are asking gas producers to cut prices, and thus profits, very materially indeed. It is therefore entirely possible that LTC renegotiations may not be a quick or easy event, even if the midstream gas buyers like E.ON and RWE believe that they have solid legal arguments. As an example, E.ON's request for renegotiations with Gazprom comes only shortly after it renegotiated all its gas contracts in early 2010.

Looking at the situation from yet another perspective, RWE entered renegotiations in early 2009 and only recently went to arbitration. It will now pursue a twin track approach of arbitration and bilateral negotiations. But this could take another 18-24 months, given the history of prior arbitrations.

We calculate that, at current spot gas prices, the potential losses in the midstream gas business could be very material. In the worst case, assuming that procurement contracts stay in the present form and that all sales contracts are re-priced, E.ON's midstream gas business could lose €3.9 billion per year and RWE €1.25 billion.

We stress that this is a worst-case scenario and is extremely unlikely as: (1) not all customers renegotiate in a single year; (2) there are very likely some hedges in place; (3) contracts can eventually be renegotiated or taken to arbitration; and (4) utilities would walk away from the business in the event of such losses. However, it is clearly a risk that is worth quantifying in the medium term to show how important these gas contract mismatches are; we believe that some losses are inevitable.

GDF Suez has a much lower exposure, even though it has a very large business, mainly because about 65% of its volumes are sold under regulated tariffs that at present allow it to charge the full LTC price. Of the remainder (250TWh) only 100TWh is exposed to the oil-gas spread in 2012, we think. In a worst case, this could lose €600 million.

Conclusion: Gas Issues Are Negative for Most Integrated Utilities

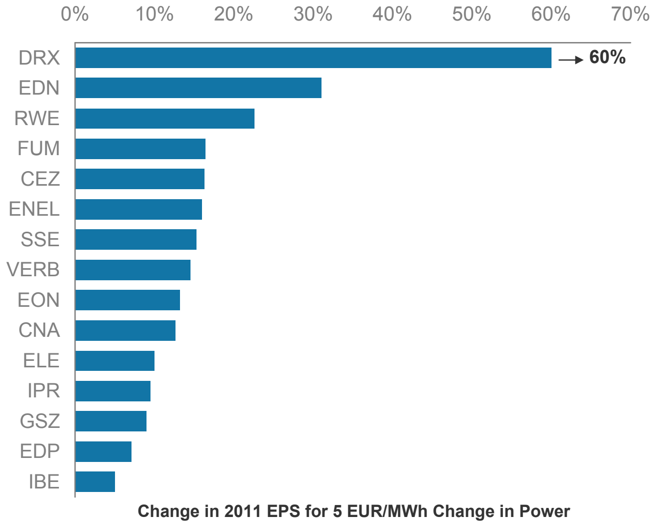
As we describe above, the gas debate affects utilities (specifically, unregulated utilities like integrated utilities and generators) in two distinct ways.

First, for all utilities with generation exposure, it will put further pressure on power prices if gas prices weaken. This is a big issue in a market that is already weak and where generation gross margins are at or close to historical lows.

This will affect many companies. Exhibit 36 highlights the impact, in terms of earnings per share, for a €5/MWh decline in power prices. This shows that most big generators have a significant exposure to this theme, with some standing out as especially exposed (e.g., Drax, RWE). In general, though, weak gas prices will be bad news for the utility industry.

Exhibit 36

Decrease in 2011e Earnings Assuming a €5/MWh Fall in Power Prices



Source: Morgan Stanley Research estimates

The second, much less widespread effect is on the midstream gas businesses, where losses will persist for a while yet, we think. Here only a few companies—E.ON, RWE, GDF Suez, Edison, and Gas Natural—have major exposure. As we showed above, this can be a material negative for these businesses if they are not successful in achieving contract renegotiations.

Most generation-focused and integrated utilities have a material exposure to gas prices and to the state of European gas oversupply. Our table of well-positioned/possibly challenged companies attempts to quantify this exposure to power generation and the midstream gas business, as well as hedges and specific company or market factors (exhibit 37).

Exhibit 37

Global Gas Glut: Well-Positioned/Possibly Challenged Utilities

Well Positioned: The Few	
EDF	Not materially exposed to gas price but rather to French regulatory change
Enel	Italian market still LTC-driven, therefore insulated from spot gas dynamics
Centrica	Lower gas prices may allow temporary outsized margins and market share growth

Possibly Challenged: The Many	
RWE	Low power prices hurt a major EU generation company; midstream losses to drag on earnings
E.ON	Low power prices drag on earnings; biggest exposure to midstream losses
Iberdrola	LNG surplus expected to put pressure on Spanish power prices
GDF Suez	Midstream losses drag on earnings; material power generation business affected by lower gas price
Edison	Gas contracts difficult in a weak gas price environment
Gas Natural	Gas contracts difficult in a weak gas price environment; Spanish power prices may weaken, too
Drax	Low gas price to drive weak UK dark green spreads, the key value driver for Drax

Source: Morgan Stanley Research

US Petrochemicals: High Oil-to-Gas Ratio Means Higher Profits

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How sustainable is the US petrochemical "ethane advantage"?

In our view, the abundance of natural gas, and specifically natural gas liquids in the US will keep US production costs among the lowest in the global industry.

Furthermore, the long lead times and lack of new petrochemicals announcements gives us increased conviction that the demand side of the equation will remain stable, leading to high capacity utilization and tight petrochemical markets.

Best positioned: LyondellBasell (Overweight) and Dow Chemical (Overweight).

The "ethane advantage". US Gulf Coast petrochemical producers to remain advantaged for some time. US producers with feedstock flexibility have been able to earn higher margins relative to Europe and Asia due to the prevalence of ethane, a natural gas liquid, as an alternative to naphtha feedstock.

We expect this "ethane advantage" to continue, and indeed improve, in the future. (We described the outlook for feedstocks in our report *Petrochemicals: Preparing for a Supercycle,* Mann et al., October 18, 2010.)

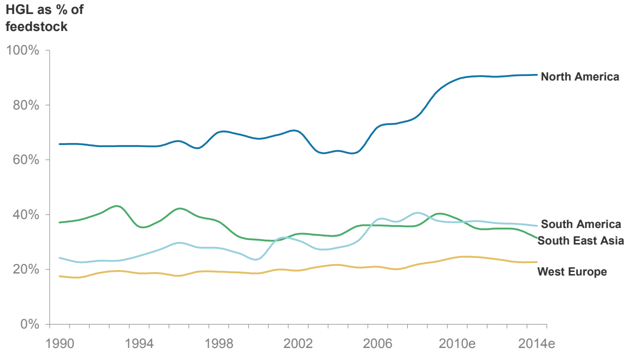
Dow Chemical, LyondellBasell most exposed. Within our coverage universe, the stocks most exposed to the US ethane advantage are Dow Chemical (Overweight) and LyondellBasell (Overweight).

- Dow earns 38% of its group EBITDA from commodity petrochemicals; its North American operations, which are benefitting from relatively cheap natural gas-based feedstock, account for 58% of those profits.
- LyondellBasell earns 80% of its group EBITDA from commodity petrochemicals; its US operations, which are benefitting from cheap natural gas based feedstock, account for 70% of those profits.

North America has used a significantly greater proportion of natural gas liquids in its steam crackers than other regions, with the exception of the Middle East (exhibits 38 and 39). In 1990-2002, NGL feedstock into steam crackers averaged 67% in North America versus 27% elsewhere in the world (Western Europe, Southeast Asia, and South America). NGL feedstocks in Northeast Asia are minimal (less than 1%) as a proportion of feedstock used.

Exhibit 38

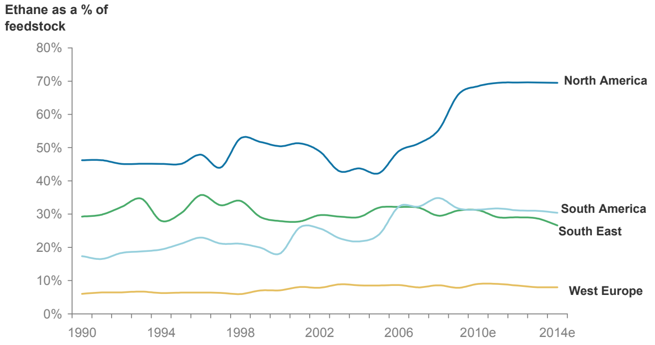
NGLs as a Percentage of Steam Cracker Feedstock



Source: Company data, Morgan Stanley Research estimates (e)

Exhibit 39

Ethane as a Percentage of Steam Cracker Feedstock

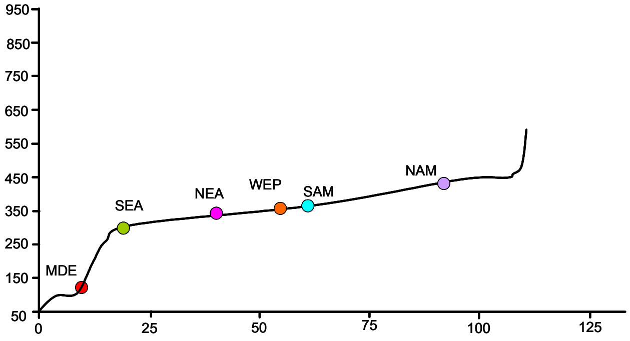


Source: Company data, Morgan Stanley Research estimates (e)

When NGLs became relatively more expensive, the US was disadvantaged … Between 2002 and 2005, the dynamics of the ethylene industry changed as natural gas prices rose relative to crude oil, approaching parity on a BTU basis. This resulted in significant price increases for NGLs, making them the highest cost feedstock for steam crackers. In response, the US industry shifted its feedstock slate to use more crude oil-based feedstock such as naphtha; NGLs as a proportion of feedstock declined from 70% in 2002 and 63% in 2005. Nonetheless, the US became the most expensive region globally to produce ethylene (exhibit 40).

Exhibit 40

Ethylene Cost Curve (2003): US Was a feedstock Disadvantaged Producer; Europe and Asia Advantaged

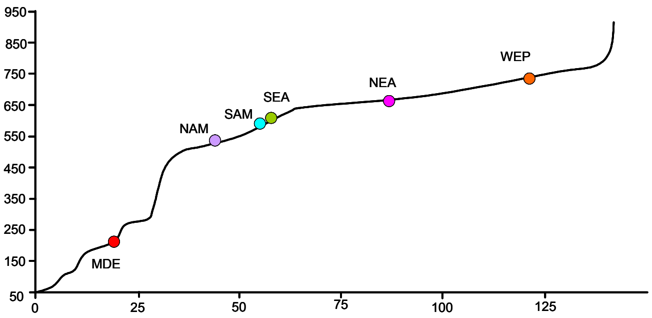


Source: CMAI

… but now the feedstock environment has shifted back again. Starting in 2006, crude oil demand surged and crude oil prices rose to record levels. While US natural gas also increased, inflation was considerably lower, and on a btu basis, natural gas became the preferred feedstock in the US. By 2009, the US had become the third-cheapest place globally to produce petrochemicals, after the Middle East and Alberta (exhibit 41). In addition, in 2008 and 2009, with light feedstock now advantaged over heavy feedstock and the commencement of the global economic recession, approximately 2.5 million tons of mainly heavy feedstock production capacity was shut down. By 2010, NGLs represented about 90% of US feedstock used and ethane greater than 70%.

Exhibit 41

Ethylene Cost Curve (2009): US Now a Structurally Advantaged Producer Relative to Asia and Europe



Source: CMAI

Consensus forecasts assume that the US will lose much of its advantage during the next three to five years. Chemical Market Associates, Inc. (and Purvin & Gertz), upon which consensus forecasts for petrochemical stocks are based, assume that WTI increases from an average price of $79/bbl in 2010 to $112/bbl in 2015, broadly in line with the forward curve. CMAI assume that US natural gas increases from a 2010 average of $4.46/mmbtu to $6.19/mmbtu and that US ethane (Mont Belvieu) increases from $0.60/gallon in 2010 to $0.83/gallon in 2015.

We think CMAI likely underestimates the advantage the US will have between 2012 and 2014. The CMAI forecasts run counter to the current natural gas forward curve, which suggests that natural gas will remain cheap for a considerable period of time. Morgan Stanley commodities strategist Hussein Allidina forecasts natural gas prices at or below the forward curve certainly until 2012.

Ethane is the critical feedstock for US petrochemicals. Ethane prices are determined by the relative balance of ethane supplied by natural gas processing plants and ethane demanded by petrochemical plants as a feedstock in the production of ethylene. Approximately 98% of ethane supply is derived from extracting ethane from natural gas by processing facilities, while a roughly equivalent percentage of demand is determined by ethylene steam cracker selection of ethane as a feedstock.

As a result, rich natural gas production, ethylene steam cracker utilization rates, and ethane feedstock selection levels by ethylene steam crackers are the key factors determining ethane prices. Both domestic and global ethylene and ethylene derivative markets influence these decisions.

There are broad conceptual parameters that help define the pricing of ethane within a supply-demand construct:

- Natural gas serves as an effective floor for ethane prices, as ethane needs to be priced at a positive spread to methane (referred to as a processing spread, fractionation spread, or keep-whole margin) to make it economic to strip ethane from natural gas beyond contractual requirements to meet pipeline specifications (BTU content, hydrocarbon dew points, contaminant levels, etc.).

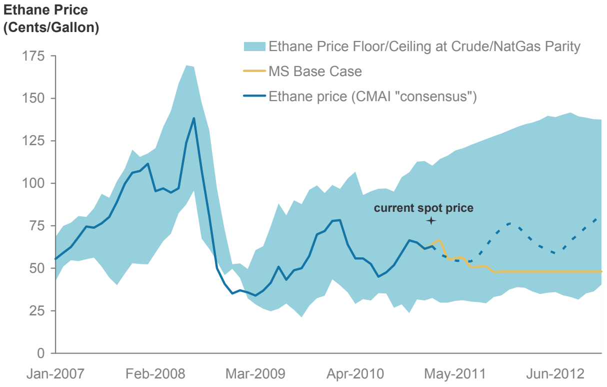
In periods of negative ethane spreads, it becomes uneconomic under certain contracts to strip ethane from the natural gas, with processors electing instead to sell the resulting higher BTU commingled product as natural gas.

In periods of positive spreads, the ethane is extracted to realize its higher relative pricing as a purity product, reducing the residue gas that remains.

Although negative ethane spreads occur at certain times and in certain geographies, these occurrences generally do not sustain themselves as supply rebalances itself through processing decisions (exhibit 42).

Exhibit 42

Ethane Price vs. Natural Gas Floor and Crude Oil Ceiling



Source: Company data, Morgan Stanley Research estimates

- *Crude oil, in theory, serves as a ceiling for ethane,* given that naptha, a crude oil derivative, is a competing feedstock for ethylene production along with propane, which can be sourced from both natural gas and crude oil (ethane comprises roughly 55% of ethylene feedstock, propane 25% and naptha 15%).

Ethylene steam crackers will select feedstock based upon cash costs, in effect requiring ethane to sell at a cost advantage relative to naptha to maintain its attractiveness.

Feedstock selection will also be derived by co-product values (each feedstock yields different products, with ethane producing a significantly higher ethylene yield than other feedstocks—north of 80%).

In practice, ethane will generally trade at a significant discount to crude oil given crude's much wider range of end markets (ethane is essentially a one-market product) and relative scarcity to its respective demand. The 20-year average ethane/crude oil ratio is 47% on an energy equivalent basis, falling closer to 40% in recent years but varying widely at any given time.

- *While natural gas supply is a key determinant of ethane pricing, we think the key bottleneck is the fractionators*, which earn a spread on removing ethane and other NGLs from the natural gas. The US currently has 33 fractionators, with an estimated total capacity of 2,429 million barrels per day and an estimated throughput of about 1,985mpbd, with ethane making up 838 million of those barrels (about 42%).

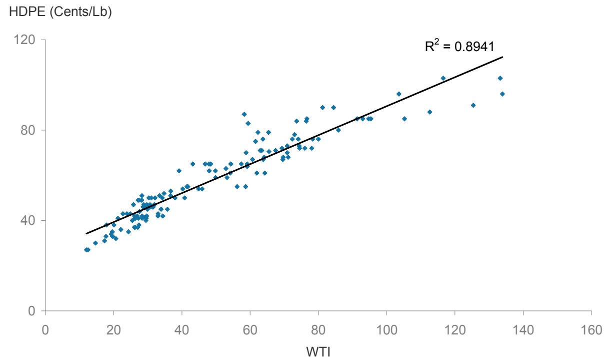
As a whole, US fractionation plants run about 82% utilized. Although there appears to be excess fractionation capacity, there are areas where fractionation capacity is tight (e.g., Gulf Coast regions near petrochemical demand areas), and we continue to see infrastructure expansions and build-out. For instance, in Mont Belvieu (the major market hub for NGLs in the US) fractionation capacity totals 823mpbd, with estimated throughput of 773mpbd (a relatively high utilization rate of around 94%), but numerous expansions and projects have been announced to increase capacity there.

According to company announcements, US fractionation capacity will increase by more than 16% during the next 18 months, from 2,430mpbd to 2,835mpbd. In our view, it is very unlikely that the US petrochemical industry can absorb such an increase in NGL production, suggesting that fractionation margins will come under some pressure.

Higher polyethylene selling prices driven by higher crude oil. Historically, there has been a strong correlation between the price of crude oil and the selling price of petrochemicals, such a polyethylene. While the US has migrated to use lighter feedstock, such as ethane, we continue to expect US selling prices to be driven largely by the export opportunity into Asia. Input costs (and thus selling prices) of the marginal producer (Asia) are driven by naphtha, which is derived from crude oil. Given the disconnect between WTI and Brent, we believe Brent (an indicator of the oil price to the marginal producer) is the key driver of polyethylene selling prices. Exhibit 43 shows the close correlation between crude oil prices and the largest petrochemical derivative, polyethylene.

Exhibit 43

Polyethylene: Strong Correlation to Crude Oil



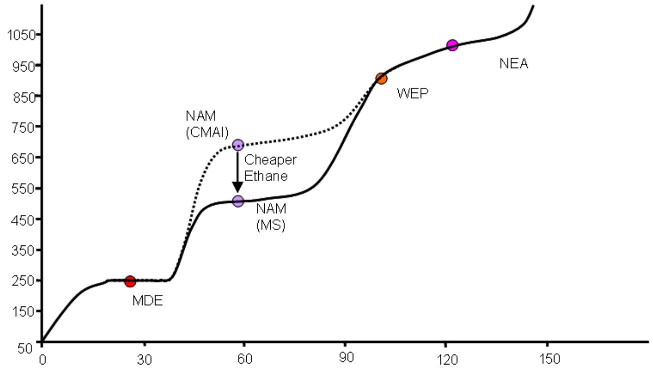
Source: CMAI, Morgan Stanley Research

Implications for Profitability

Exhibit 44 shows how we expect global profitability to look for integrated polyethylene producers in the US and ex-US regions. Under our assumptions for natural gas and ethane margins (with polyethylene prices determined by the oil price forward curve), US cash margins will likely be about 80% higher than those forecast by CMAI. On our estimates, between 2010 and 2014 this will likely lead to US cash margins that are 2.4x the average achieved between 1990 and 2009 (exhibit 45). Investors likely underappreciate the free cash flow that the US petrochemical companies will generate during the next five years.

Exhibit 44

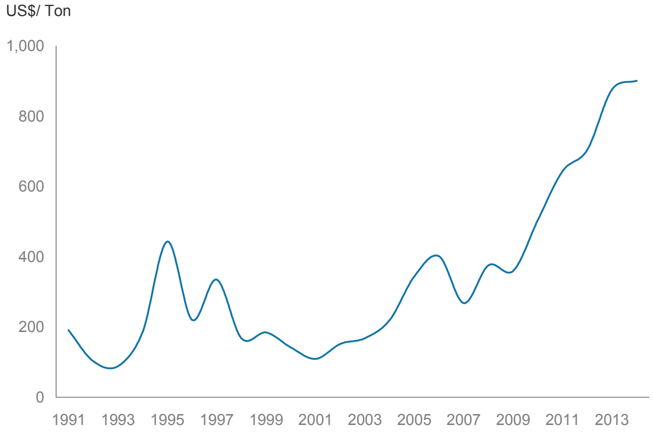
US Ethane Advantage Likely to Be Greater Than Assumed by Consensus After 2012



Source: Morgan Stanley Research, CMAI

Exhibit 45

US Cash Margins: Preparing for a Supercycle



Source: Company data, Morgan Stanley Research

Chlor-Alkali Also a Clear Beneficiary of Cheap Gas

Chlor-alkali is another area where US chemical companies can effectively arbitrage cheap natural gas input costs with expensive oil-based international competitors. The chlor-alkali process is energy-intensive, and US producers that use natural gas for their energy requirements have a significant advantage over producers in other regions that use oil- or coal-based energy sources.

PPG Industries, Dow Chemicals most exposed. Within our coverage universe the stocks exposed to cheap gas in their chlor-alkali operations are PPG Industries (Underweight) and Dow Chemical (Overweight).

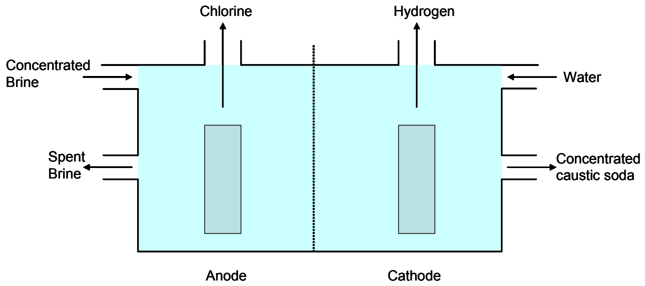
- PPG earns 16% of its group EBITDA from its commodity chemicals business, which comprises its chlor-alkali operations, and uses natural gas for about 75% of its energy requirements.
- Dow earns less than 5% of its group EBITDA from its chlor-alkali business, but Dow is likely the largest US producer of chlor-alkali, with most caustic soda and chlorine used internally within the company's performance and specialty divisions.

Other companies, not covered by Morgan Stanley Research, that benefit to varying degrees are Georgia Gulf, Olin, and Occidental. Georgia Gulf suggested at its investor day in February 2011 that it was now exporting 25% of its polyvinyl chloride (PVC, a chlor-alkali derivative) due to its cost advantage.

Chlor-alkali is used to produce caustic soda and chlorine; it is one of the largest chemical segments by value. The applications of its products are so diverse that the majority of all consumer products depend on them at some stage of production. Although there are a few other methods of production, electrolysis of brine (salt solution) accounts for 97% of the world's chlorine capacity and 100% of the world's caustic soda capacity. Simply put, the process entails passing electricity through brine from an anode to a cathode (exhibit 46). The largest cost component is the energy consumed in the process, the source of which determines competitive advantage.

Exhibit 46

Electrolysis: Production of Caustic Soda and Chlorine



Source: Morgan Stanley Research

PPG's margins are likely to be 1,000 basis points higher than in the last cycle. PPG use natural gas to supply approximately 75% of its energy requirements, with the balance derived from coal- or hydro-based electricity. It uses 50-55 trillion btu/year and typically hedges approximately 50% of its requirements. With natural gas prices expected to remain low in the US for some time, PPG should be advantaged relative to Olin, which obtains about 15% of its power requirements from natural gas and purchases the rest in the open market. Based on the current forward natural gas forward curve, PPG's commodity chemical margins will be about 1,000 basis points higher in this cycle than in the last one (for the same ECU pricing). On a group basis, we estimate that a $1/million-cubic-foot decrease in the natural gas price is worth an incremental $65 million (3.7%) in operating profit for PPG, with approximately $50 million of it in the commodity chemicals division and $15 million in the glass division. When leveraged through PPG's P&L, such an increase in operating profit would translate to a 4% increase in pretax profit and 5% increase in EPS.

Clean Energy: Economics As Well As Politics Driving Growth

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Regulation driving renewables growth; market underestimates the importance of gas demand.

We expect more than 700GW of new renewables capacity to be built in Europe, the US and China over the next decade, mainly in wind and solar power. Strong national and international targets and attractive subsidies schemes drive growth. We expect renewable generation to displace traditional gas plants on the power grid and thus strong renewables growth is negative for gas demand.

We favour low-cost players or technology leaders, with scale as a way to play long-term renewable capacity growth.

Best positioned: GCL-Poly Energy (Asia—Overweight), **Trina Solar** (Asia—Overweight), and **First Solar** (US—Equal-weight) are our preferred plays in global solar. **Goldwind** (Asia—Equal-weight) and **Vestas** (EU – Equal-weight) would be our preferred names in wind on a three- to five-year view.

We expect renewable generation technology to be a major contributor to all new power-generation capacity that will come online globally through 2020. Given limited growth opportunities in hydropower and geothermal power, we expect wind and solar power to be the main technologies to grow over the next 10 years (exhibit 47). Our base case assumes that more than 700 gigawatts (GW) of new capacity in renewable energy will be added in Europe, the US, and China alone from 2010 to 2020; this rise in new capacity will be driven by supportive regulation and a falling cost base (exhibit 48).

However, we would point out that these estimates are, if anything, relatively cautious and assume that these nations will remain behind their current targets. Our bull case captures significant upside if national targets are met or exceeded.

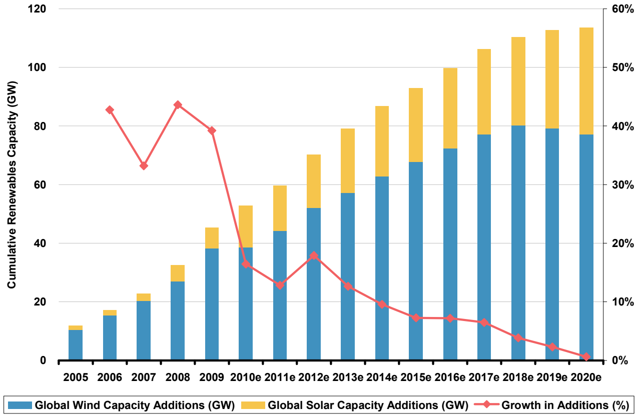
Regulation Remains Key, European Policy Leads the Way

Regulation remains a key driver behind the growth in capacity for renewable energy both at regional (e.g., European) and national levels, as governments generally agree on the need to mitigate climate change and improve energy security. While the cost of renewable energy is falling, we expect government support to remain strong and to encourage sustainable growth in the industry throughout the next decade.

The Europe Union remains a global policy leader. The EU has set binding targets for reductions in greenhouse gas emissions for its members and has committed to increasing its generation of electricity from renewable sources to 20% by 2020. The US and OECD countries are now engaged in political and economic negotiations on the issue, but have yet to set binding long-term targets.

Exhibit 47

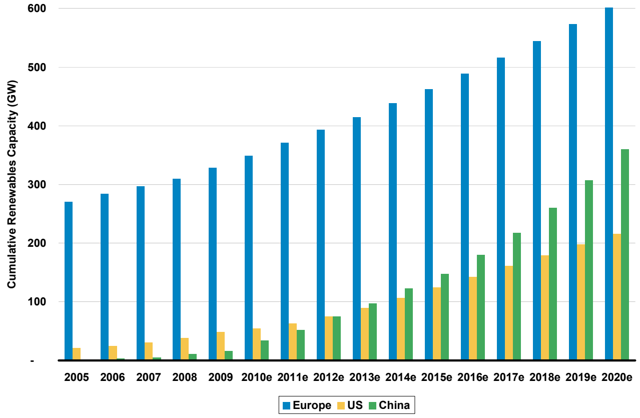
Wind-Solar Additions to Grow to Over 100GW per Year by 2017



Source: GWEC, EPIA, Morgan Stanley Research estimates (e)

Exhibit 48

China, US, and Europe Are Key Growth Markets for Renewables



Source: GWEC, EPIA, Morgan Stanley Research estimate (e)

Technology and Scale Reduce Generation Costs

In general, renewable energy technologies remain more expensive than traditional energy generation and so require subsidies to compete (exhibit 49). Subsidies play two key roles: They drive near-term investment returns and create economies of scale to help to bring the cost of renewable energy generation closer to that of conventional generation.

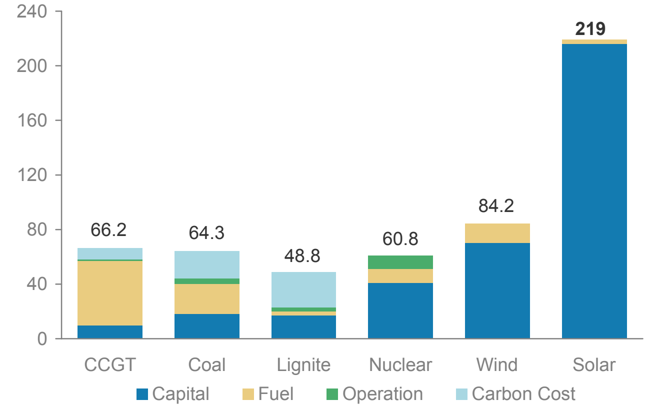
Other than large hydropower generation, where there are limited growth opportunities, wind power generation remains the most cost-competitive renewable technology. As such, we expect it to remain the main driver of growth in most markets. Solar power is still at least three times more expensive than traditional power technologies, but costs are falling rapidly as the industry scales up. We expect solar module costs could fall another 30% by early 2012.

Estimates Based on Bottom-up Approach

We use a country-by-country approach in determining our forecasts for renewable energy growth. We first assess the attractiveness of regulation and project returns in all the main markets and take into consideration long-term targets, both mandated and indicative. We cross check this data with a detailed supply model to help generate a view on competition and equipment pricing direction.

Exhibit 49

Generation Costs: Renewables Require Subsidies to Compete, but Costs Are Falling



Model assumes LT oil price at $90bbl and coal at $100/t
Source: Morgan Stanley Research estimates

MORGAN STANLEY BLUE PAPER

Global Gas

Regional Overviews

Europe: Gas Markets to Stay Threatened by the Global LNG Glut

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Consensus wrongly expects a near-term firming in LNG markets and a softening of European gas pricing pressure. Our analysis indicates that for the next five years European demand for LNG will stay flat at best and remain under threat from an oversupplied global LNG market.

Flat gas demand to 2015. Modest European GDP (2.1%) growth expectations drive our forecast of stagnant industrial gas demand. The power generation sector will see modest absolute demand growth, but this, at the margin, will be met by new renewables capacity. With expected flat residential gas demand, we see only 1.2% CAGR overall gas demand growth in the region over the next decade.

Oil-linked gas contracts will stay under pressure for four to five years (especially if oil prices continue to rise) and will require Statoil and Gazprom (amongst others) to restrict production in trough-demand summer months.

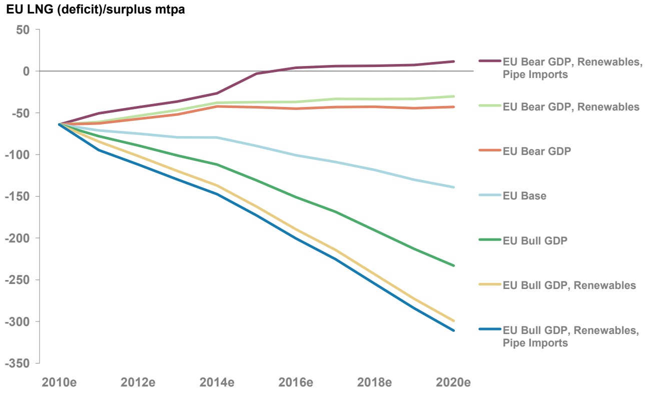
Oil linkage to persist, but in a weaker form. We expect the oil-linked model to continue to dominate for several more years, but for more frequent price resets, and with softer terms as each negotiation round concludes. We forecast the long-term European contract price to average \$8.5-10.5/mscf (equivalent to 8-10% gradient to MSe base case \$105/barrel oil, versus 11-12% historically) and for spot prices to seasonally oscillate around this figure.

Unconventional gas a red herring, for now. We see significant long-term potential in European tight gas but little scope for this resource to affect Europe's gas balance materially before 2020.

Natural gas vehicles (NGV) and electric-drive vehicles (EV) will not make a visible dent. NGVs are not currently a plausible answer to Europe's energy challenges as long as gas prices are oil-linked. EVs make far more sense to us, but our calculations indicate the potential gas demand from even high new vehicle EV penetration rates is too small to matter (8bcm by 2020).

Exhibit 50

EU Implied LNG Import Scenarios



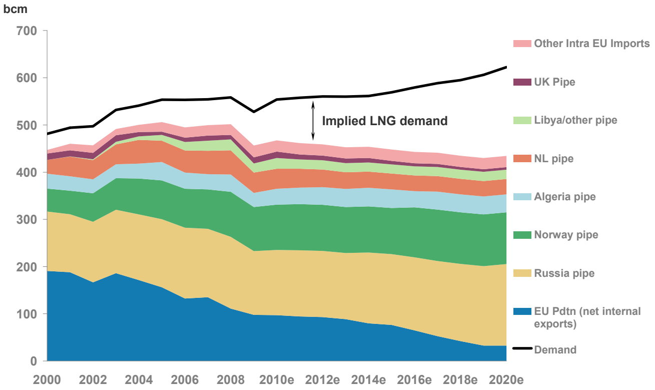
Source: Morgan Stanley Research estimates

Europe Is Structurally Short Gas …

The fundamental overall gas picture is, of course, very bullish in Europe: local production amounts to only 50% of demand, and even with significant gas imports via pipe from Russia, Algeria, and Norway, the continent still has a large implied demand for LNG (exhibit 51).

Exhibit 51

EU Need for LNG Is Not Growing Until After 2015



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

… but There's Plenty of LNG Out There, so No Problem!

The issue is not whether Europe needs LNG or not, it is whether there is enough spare LNG capacity in the world to meet Europe's needs in the next few years. We think the answer to that question, which we outline in the next few sides, is not only an unambiguous yes, but actually our concern is the opposite—we see a sustained glut of global

LNG for the next five years, whereas we forecast Europe's LNG demand over the same period to be close to flat.

Power Generation Growth Will be Lower Than Consensus Expects as Renewables Take Share

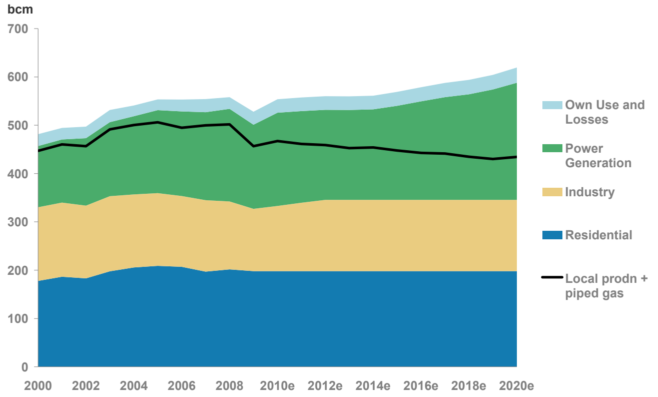
Exhibit 52 shows historical trends and our forecast for European gas demand by segment; we model each segment separately and conclude that total power demand will have a 1.6% CAGR over the next 10 years, to 4400TWh by 2020.

Within this industry growth, we expect gas-fired power generation (mainly CCGT) to gain market share slightly, from 24% in 2010 to 26% by 2020. However, the market share of the renewables sector is set to increase materially, by 600bps, to 30% in 2020. This renewables growth is the main reason that gas-fired demand will be lower than many think. If renewable targets are met, then there is simply much less need to meet production from gas-fired power stations.

In the other parts of the generation industry we do not expect new nuclear build (other than the 4GW already in construction) to be operational before 2020. We model substantial coal plant closures (54GW), the result of environmental directives, poor economics in Europe at present, and ageing plants. Oil plants will also close, we believe, or run very infrequently as peaking units.

Exhibit 52

EU Gas Demand: Only Modest Growth Through 2020



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Gas and EU power generation

In forecasting the demand for gas from power generation in Europe, we model the growth in the overall EU power generation market and in the different types of power generation technology.

Our overall forecast for power demand is 1.6% per year through 2020, as the big demand decline in 2009 recovers around 2012 and normal growth rates resume. We have not made dramatic assumptions on energy efficiency, so arguably this forecast is quite conservative, but in the next decade, we believe, the risks are more skewed to the downside for power demand because of energy efficiency targets than they are to the upside because of developments like EV rollout.

We then forecast the capacity closure on the existing European power fleet and likely new build capacity, especially in renewables, and these factors combine to determine the demand for gas from the power generation sector.

Coal: A declining source of power generation. Overall, we expect coal's market share in power generation to decline from 25% to 21% by 2020. We expect the majority of the closures in the coal-fired generation fleet due to: (1) ageing plants; (2) the impact of the EU LCPD before 2015; (3) the EU Industrial Emissions Directive (IED) after 2015; and (4) the fact that the generation spreads (i.e., gross margins) for coal-fired generation capacity in Europe are weak at present (exhibit 53).

We forecast 54GW of coal-fired capacity closures by 2020, with significant closures expected in the UK (also in a variety of other markets, though to a lesser extent).

Exhibit 53

Case Study: German Power Generation Capacity Additions and Potential Closures

	Additions (GW)	Closures (GW)
Fossil Fuels	**14.8**	**-23.0**
Lignite	2.7	-7.0
Hard Coal	9.6	-4.9
Gas	2.5	-5.7
Oil/Other	0.0	-5.4
Renewables	**30.2**	**-0.1**
Wind	5.9	0.0
Solar	24.3	0.0
Other	0.0	-0.1

Source: Morgan Stanley Research estimates

The last couple of years have seen new-build, coal-fired generation proposals struggle. Many plans to build new coal plants were cancelled, often due to planning and environmental approvals. Some new coal plants were cancelled even where these approvals had been given, often because of financial issues. A sizeable amount of new coal capacity is in construction and will proceed, so there will be some new coal-fired generation capacity commissioned in Europe (16GW), and we include this in our model.

However, we believe it will be very difficult for any further coal-fired projects to get approval unless they are carbon capture and storage (CCS) fitted, which makes the economics of the project very unattractive. Thus, we see little scope for any more coal new builds.

Oil: Also in decline as a power generation source. There is little chance of material new oil-fired capacity because of both environmental and cost implications. We assume 40GW of capacity closures and that the plants remaining open run on very low-load factors. Oil is essentially used as peaking reserve, where it will remain in operation; thus, we assume its market share will decline from 3% to less than 0.5%.

Nuclear: Lifetime extensions and new builds increase capacity. In a range of European countries (the UK, France), nuclear is a preferred source of future power generation, and in others (Italy) it may be moving further up the agenda. But our forecasts are not predicated on the possibility of new nuclear plants, especially given the very long permitting and build process, not to mention the time and cost over-runs that have plagued some projects.

Therefore we include only the 4GW of capacity that is now in construction. We also include the lifetime extensions that have been announced in the UK and Germany, which mean we expect no nuclear plant closures before 2020.

These lifetime extensions, especially those in Germany, mean that the nuclear production we forecast is now materially bigger than it was previously (German nuclear lifetime extensions for all existing facilities were agreed in late 2010). We forecast nuclear market share will decrease only marginally from 24% to 23%.

Renewables: A fact, not a fad. Perhaps the biggest change in the shape of the European power generation sector is the growth in the renewable power generation segment. We continue to forecast material growth in the renewable segment to meet the EU 20-20-20 targets.

One of the trends that we think is key here is that we have seen no significant wavering of most member states' commitment to meet EU targets. This means that there will be continued growth in wind and solar capacity in particular.

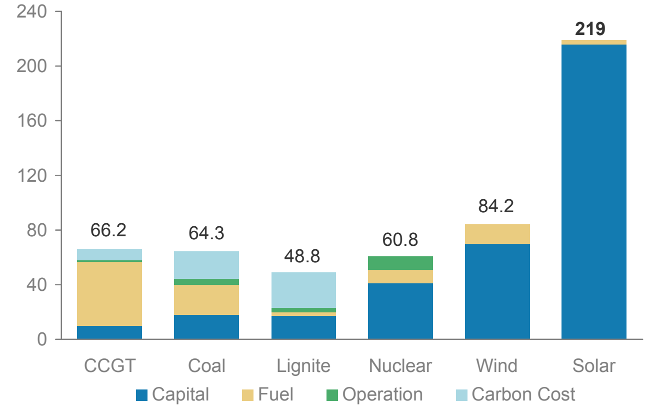
We forecast that renewable generation (including hydropower) will increase its capacity from 349GW in 2010 to 600GW in 2020, increasing its market share from 24% to 30%.

Gas fills the (smaller) gap. Our model assumes that gas is the fuel that bridges the generation market gap. This fits with the ability to build gas-fired power stations relatively quickly and easily and the fact that gas is an environmentally more acceptable fuel. The big increase in renewable generation expectations is the source of a lower demand for gas from the generation sector. It may be that more gas-fired power stations are constructed as back-up generation for sometimes unreliable renewable generation. But even if this is the case, renewables will always have priority dispatch due to the subsidy mechanisms, and thus these gas-fired power stations will not run ahead of renewables (exhibits 54-55).

For these reasons, we now forecast that gas-fired power generation market share will increase from 24% in 2010 to 26% in 2020.

Exhibit 54

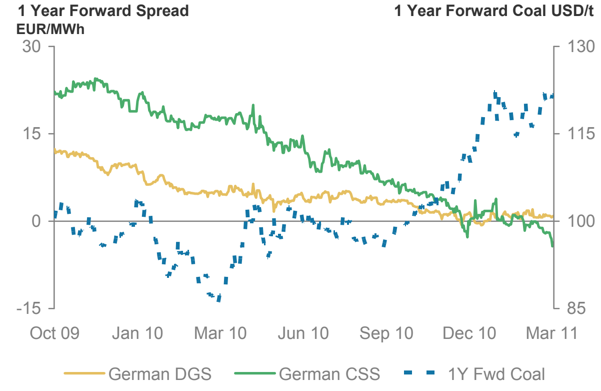
Economics of New Gas and Coal Projects Similar, but Renewables Will Proliferate



Source: Morgan Stanley Research estimates

Exhibit 55

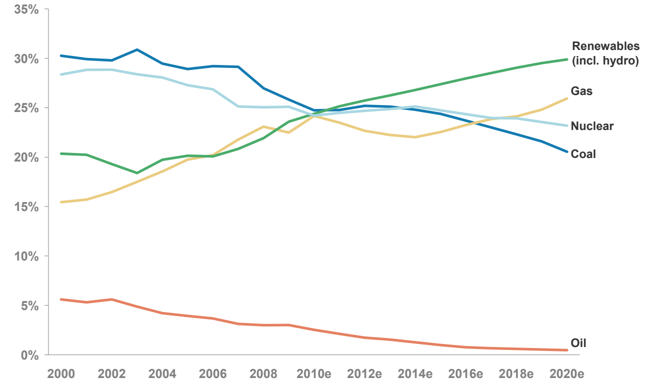
European Power Prices Imply Weak Margins for Both Coal And Gas-Fired Power Plants



Source: Bloomberg, Morgan Stanley Research

Exhibit 56

Renewables to Take Europe Power Generation Share From Coal, Oil, Nuclear



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Transport: Natural Gas Vehicles (NGVs) to get little traction in Europe. We discuss NGVs more fully in Appendix A. We decided to exclude them from our European scenarios simply because we believe that oil-linked pricing is likely to largely persist in Europe, and unless these evolve to a much lower oil-linkage than today it is hard to argue either that consumers will see any material fuel price advantage in using NGVs or, more importantly, that the industry will invest in the distribution and storage infrastructure required.

Cars: Electric Vehicles (EVs) could eventually transform personal transport, but not medium-term gas markets. Electric cars are a more obvious path to substitute increasingly expensive diesel and gasoline. However, the energy efficiency of EVs is about 2 kilometres/megajoule (km/MJ) vs. 0.6 km/MJ for gasoline cars, and this higher energy efficiency ironically makes EVs replacing gasoline (or diesel) cars a relatively unimportant scenario in our models; in other words, the implied increased need for power generation does not actually materially increase overall gas demand, even when a large number of diesel or gas vehicles are replaced.

Even in our most optimistic EV scenario for both the US and EU combined (where 50% of new car sales by 2020 are EV), and even if all the incremental power demand was met solely by gas-fired plants, we calculate that the additional gas required would be a mere 16bcm—or 1.3% of our combined forecast US/EU demand.

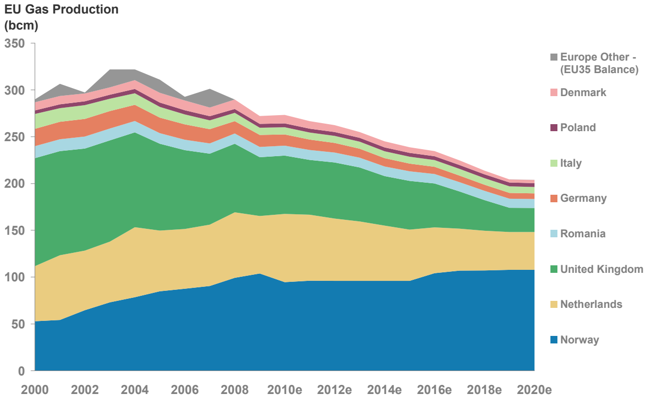
Local Supply to Continue Falling

On the ex-LNG supply side, it is not very controversial to state that we expect ex-Norwegian Continental Shelf (NCS) gas production to continue falling as the battle with mature field declines inevitably starts to eventually lose ground (exhibit 57).

Unconventional gas unlikely to play a major role in Europe before 2020. We also considered the potential for EU unconventional gas production to emulate the transformation seen in the US in recent years. However, we concluded that 1) it is too early in the appraisal process to know whether *any* unconventional gas will ever be economic in Europe, and 2) even if within the next two to three years exploration and appraisal work shows these resources are indeed commercial, and even if Europe managed to repeat the rapid growth seen in the US (and given the lack of small exploration/production, onshore service industry, and population density issues, this seems unlikely), we could be looking at around a 10bcm contribution by 2020—not material enough to warrant a separate scenario, in our view.

Exhibit 57

EU Indigenous Supply Is in Structural Decline



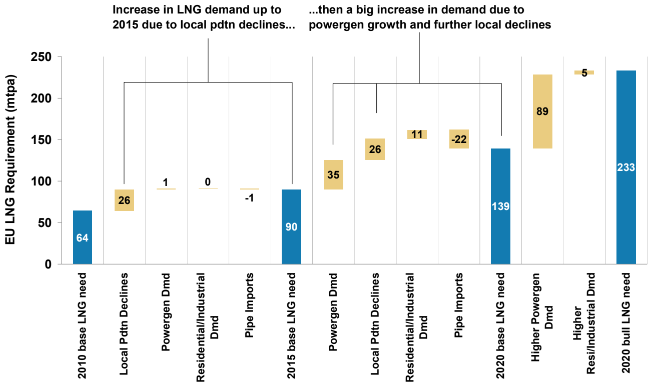
Source: WMAC, BP Stat Review, Morgan Stanley Research estimates (e)

Piped supplies: After Nord Stream there is much talk, but no FIDs as yet. On the pipeline side, Nord Stream (28bcm) will be on-stream by end 2011. But even though it gives Gazprom increased optionality on export routes, we assume that it will not add to the overall physical supply of gas, at least not whilst it is priced off oil and there is a significant global LNG glut on Europe's doorstep. On other projects there is considerable uncertainty over whether Nabucco, Southstream, or some other link to Azerbaijan and/or Iraq will get sanctioned and built. In our base case we keep things simple and assume none of the above; we want to analyse the situation given current confirmed infrastructure plans.

Modest LNG demand growth for five years, then a pickup. We forecast 7% LNG demand growth in Europe for the next five years. This sounds high, but it amounts to 35bcm and will still leave the world in a materially oversupplied LNG position. After 2015, we expect 9% LNG demand growth as coal capacity load factors plateau (at 60%) in the power generation sector, whilst coal capacity sees net closures (due to CO_2 pricing). In this case, CCGT load factors will increase and power generation sector demand growth for gas will make a difference. The lower pipe imports after 2015 shown in exhibit 58 are due to our expectation that Norwegian gas production will start to decline.

Exhibit 58

EU Implied LNG Demand (2010e – 2015e – 2020e)



Source: Morgan Stanley Research estimates

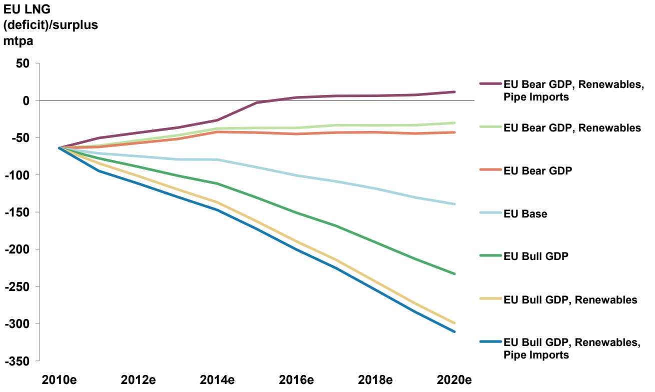
LNG Import Scenarios: GDP and Renewables Matter Most

There are a large number of possible scenarios when it comes to European gas supply/demand, so we restrict ourselves to what we believe are the most significant three: the regional GDP outlook, possible new pipeline supplies, and renewables power plant construction.

In exhibit 59 we show how the European LNG balance changes as each of these scenarios is layered in; clearly we see that only a very unlikely combination of events could end Europe's need for LNG, whereas in all likelihood we will see an increasing shortage after 2015.

Exhibit 59

EU Implied LNG Import Scenarios



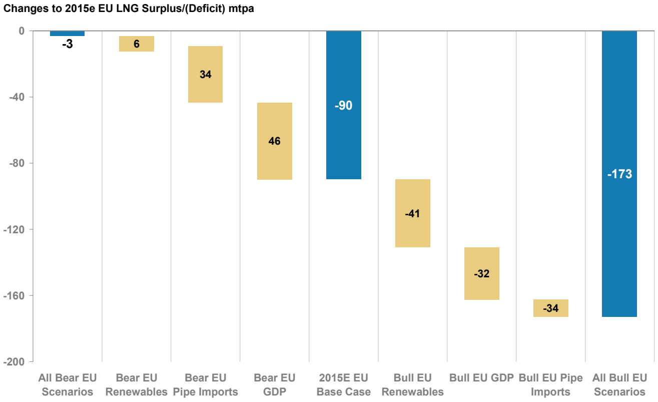
Source: Morgan Stanley Research estimates

Flexing the Assumptions: Low GDP and Delayed Renewables Matter the Most

Looking at the impact of changing each base case assumption on implied LNG demand in Europe (exhibit 60), lower-than-expected GDP growth would have the greatest impact in terms of reducing Europe's LNG requirements. On the more bullish side, we were surprised to discover that our new renewables capacity assumption is the most significant driver; that is, if we assume delays to the base case solar and wind projects, this will drive European LNG demand materially higher (as CCGTs will need to deliver the TWh instead).

Exhibit 60

Bear-Bull: Changes to 2015e EU Base Case Imports



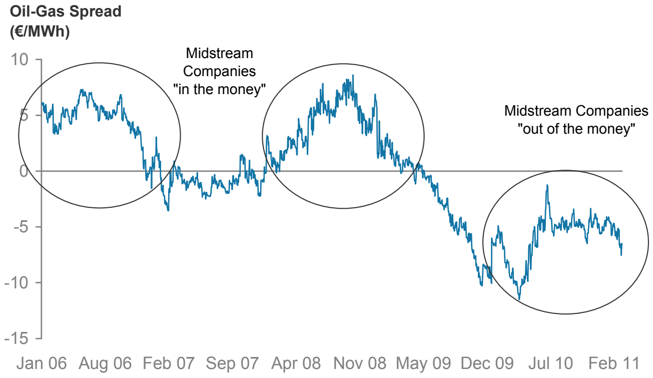
Source: Morgan Stanley Research estimates

EU Oil-linked Contracts to Stay, but In a Softer Form

Our analysis indicates that we are facing a rise in surplus global LNG in 2011 and that we will have to endure this global surplus until 2016 at least (in our base case). Thereafter, things tighten, but five years is a long time away for many market participants. This medium-term surplus helped depress European spot gas prices relative to oil-linked contracts early last year. And although this oil-gas spread has narrowed, it remains negative, which is a very difficult position for many midstream gas companies like E.ON, GDF Suez, RWE, and ENI (exhibit 61). The recent strength in crude, coupled with our soft medium-term outlook for spot gas prices, suggests that this oil-gas spread can widen yet again (exhibit 62).

Exhibit 61

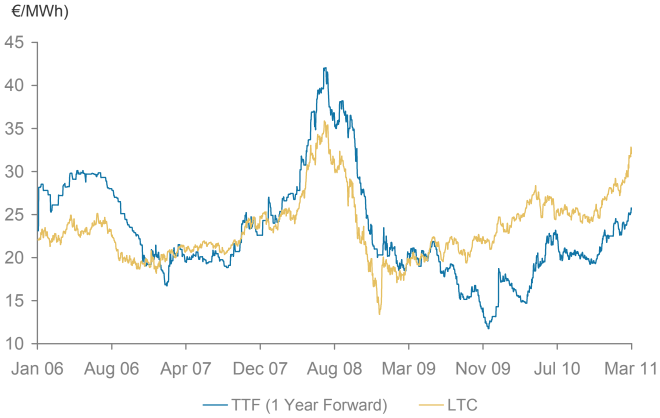
The Forward Oil-Gas Spread Remains Negative, Though the Spread has Narrowed, Partly due to Abnormally Cold Weather …



Source: Bloomberg, Morgan Stanley Research

Exhibit 62

… as Spot Gas Prices Are Still Below Long-term Contract Prices and Could Decline Again



Source: Bloomberg, Morgan Stanley Research

The question naturally becomes one of whether 1) long-term (as in 20 years) gas contracts are appropriate for major consumers (utilities, independent power generators, and industry) and whether 2) such contracts should be mainly linked to oil prices, as they are today.

We believe the answer to the first question is no: 20-year contracts do not seem to be appropriate in a market where the end consumers are only committing to two to three years of payment terms. However both the midstream gas buyers and the gas producers seem committed to long-term contracts.

The answer to the second question is yes, but with some important caveats that are negative for the major producers. We think gas will still be sold under a “term contract” structure (but possibly shorter than 20 years or with more regular resets) and that oil of one form or another (crude, low sulphur fuel oil, diesel, etc.) will remain the dominant reference price, but that pricing will have to be more flexible.

A liquid spot gas market in Europe is clearly beginning to develop. As shown in exhibits 63 and 64, the growth in volumes traded has been exponential, although some of this is likely a function of the gas oversupply. And some midstream companies are demanding either that their procurement contracts are linked to spot prices or that the base price is cut to close the gap with spot. Clearly the gas producers are less than keen for this to happen (exhibit 65).

The bargaining power in the industry has changed. Contract renegotiations in 2010 helped midstream buyers somewhat but did not go nearly far enough, especially if our gas and oil outlook is correct. Losses will persist. This first round of renegotiations saw producers cede minimum take levels and soften the indexation terms, accepting about 15% spot indexation rather than the roughly 98% crude indexation.

But to try to stop the losses and restore the profitability of the midstream businesses, midstream utilities are attempting to further renegotiate the LTCs. Renegotiations are ongoing, but we expect them to be lengthy; both sides insist they have very strong legal cases.

The contract renegotiations typically focus on a number of things that the midstream customers are seeking to change in their favour. These customers aim to:

- Close the spread, or gap, between the long-term contract price and spot gas prices, normally achieved by rebasing the initial contract price (often called the “Po”).

- Alter the indexation terms to avoid big differences in the buying and selling prices and thus reduce the risk profile for the midstream players.
- Aim to increase volume flexibility.

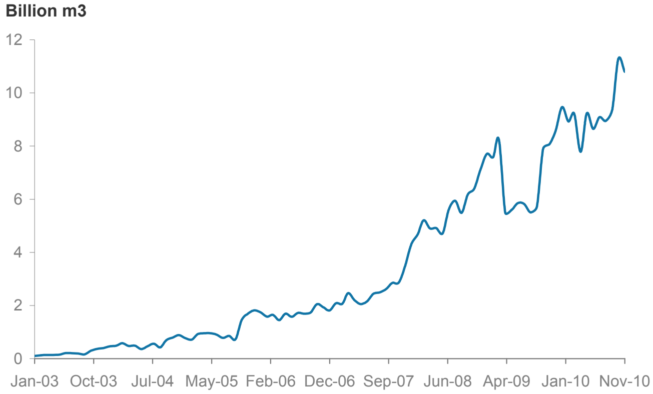
Indeed, RWE started to renegotiate its LTCs in early 2009 and is only now entering arbitration on some of its contracts. Arbitration can be a very long process, suggesting that a final solution could still be at least 12 months away—possibly as long as 18-24 months. We expect E.ON to enter arbitration in April 2011, and thus we expect a similar lengthy process there.

Our forecasts assume that there are material midstream gas losses for both E.ON and RWE in 2011 and 2012 before recovering back to a normalised level of profit on these contracts in 2013. We would argue that these are quite optimistic assumptions, especially if the negotiations drag on for longer than expected. In a worst case, these losses can be very material indeed. Again, we stress that these are not baked into our current forecasts.

For GDF Suez, its midstream gas business contains gas sold to many different types of customer, some regulated, some not. We forecast losses for the pure midstream exposed volumes (30TWh in 2010, 80TWh in 2011, and 100TWh in 2012) as we assume that the current negative spot/LTC spread is crystallised. This implies losses of around €480m in 2011 and €600m in 2012, but these losses are offset by other profits (from gas supply to other customer types, LNG arbitrage, shipping and trading) in the division. Thus, for the midstream gas (supply and market) business sub-unit overall we forecast EBITDA to be €400mn in 2011 and €500mn in 2012.

Exhibit 63

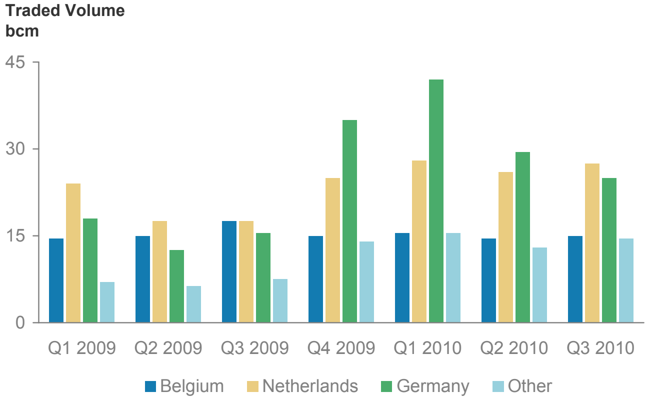
Liquidity at the TTF Hub Continues to Increase …



Source: GasTransport

Exhibit 64

… as It has at Other European-traded Hubs, Especially in Germany



Source: Morgan Stanley Research

Exhibit 65

The Pros and Cons of Long-term, Oil-linked Gas Contracts in Europe Versus Spot

		Spot gas	Long-term contract, oil-linked gas
Buyers	**Pros**	- Has traded at a discount to oil-linked since Sept 08.	- Gas supply security in structurally short markets. - Priced off indices that are hard to manipulate (i.e., oil products).
	Cons	- Risk of inability to access gas when it is needed most, at any price. - EU spot markets are illiquid—risk of price manipulation.	- Has traded at a premium to spot since Q1 09.
Producers	**Pros**	- No obvious attraction for producers at present.	- LT contracts underpin large infrastructure projects. - Ties customer to producer—supply competition is thus restricted.
	Cons	- Evolution of a deep, liquid spot market could encourage competition (e.g., tight gas producers). - Pipe suppliers would have to compete head to head with global LNG on all of their production, and global LNG is completely outside of their control.	- Subject to oil price volatility that may not reflect gas market conditions or infrastructure investment costs.

Source: Morgan Stanley Research

Henry Hub Has a Limited Impact

The US is not necessarily an energy island forever when it comes to gas. Wood Mackenzie estimates that a structural gap of $3.6/mscf between European and US prices would justify the construction of Gulf Coast liquefaction plants (we estimate $4-5/mscf). European producers can see the same potential threat and we assume they take this into account when they enter gas price renegotiations with their major customers. This theoretically puts a $4-5/mscf premium to Henry Hub cap on long-term EU prices.

More Challenges Ahead for Piped Gas Suppliers and Mid-Stream Players

Europe will see modest LNG demand growth over the next five years in the face of a growing global surplus of the product. This can only put further pressure on European spot prices. In the face of this pressure the rational reaction of the major piped gas suppliers (Russia, Norway, and Algeria) would be to repeat the actions seen in 2010 and materially lower production during the trough demand summer months.

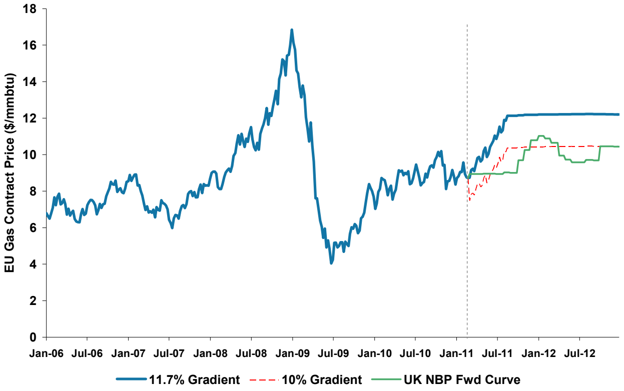
The same pipeline suppliers will most likely face several more years of aggressive negotiation on the side of the major customers, who will want yet more flexibility over contract volumes and gradient of oil price linkage (as well as the base level, or "Po'').

We assume the gradient of the link to oil will soften to an 8-10% range from the 11.7% we have seen on average in recent years. (In general we have found that gas contract prices have until recently been broadly equal to Brent x 70% (to convert to a fuel oil proxy) and then divided by 6 (to convert to mscf from boe), and that this equates to Brent x 11.7%.)

This drives our European contract gas price forecast as shown in exhibit 66. We also show our spot (NBP) forecast, where we basically expect an eventual convergence to contract as global LNG tightens after 2015.

Exhibit 66

EU Contract Gas Price Outlook



Source: Bloomberg, Datastream, Morgan Stanley Research estimates

US: Comfortably Balanced For Now–But Will It Export?

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Base case: Not a major LNG exporter or importer for the foreseeable future. Our base US scenario sees the US LNG balance close to neutral (in a global context) over the next few years (exhibit 67). We expect continued unconventional gas production growth to offset conventional declines and for overall gas demand growth to be modest. This neutral outlook clearly has risks, as we highlight in our scenarios. The most obvious one is that material liquefaction capacity gets sanctioned and the country becomes an exporter.

Henry Hub to stay under pressure due to modest local demand growth versus abundant local supplies. Morgan Stanley equity analysts assume $5.50/mmbtu long-term US gas prices based on an expectation of marginal cost of supply (in the current demand outlook) at $5-6/mmbtu.

Export scenarios: Another threat to global LNG markets. Liquefaction construction requires a multi-billion dollar investment on a 20-year structural price difference of $4/mscf or more to Europe and/or Asia. Despite this challenge, two projects are progressing well and several more have been proposed. We only include high-certainty projects in our base scenario, but it is conceivable that this number will steadily rise the longer that Henry Hub stays low relative to oil-linked Asian and European gas prices.

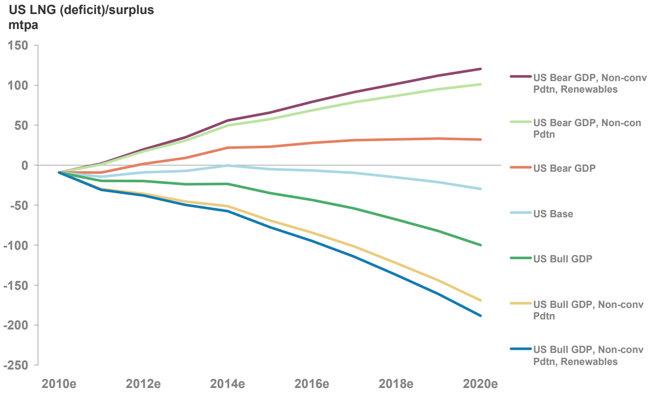
Implication for Europe: Low Henry Hub implies uncontracted LNG will continue to look for a home in Asia and Europe. The structural threat to Europe's gas pricing raised by the US unconventional gas phenomenon (alongside the recession) is set to persist for several more years.

NGVs and EVs: Upside, but little appetite. Gasoline currently costs more than $100/bbl (or a retail price of c.$3.5/gallon) and the US imports about 65% of its oil needs. Natural gas currently costs approximately ¼ of gasoline on an energy equivalent basis and the country is close to self-sufficient. There seems to be logic in assuming the US will embrace more gas consumption for transport, but as yet there appears little political or consumer enthusiasm.

Land grab to continue. International oil companies and national oil companies will continue to be attracted to the gas resource and fiscal/legal stability of the US, despite the medium-term weak gas price outlook.

Exhibit 67

US LNG (Deficit)/Surplus– a Neutral Base Case



Source: WMAC, Morgan Stanley Research estimates (e)

The Backdrop: Challenging for Prices, Risk of Exports

We see near-term US gas prices as remaining challenged. Although low gas prices have spurred demand, the market remains oversupplied owing to robust production. On an annual basis, 2010 US dry gas production averaged 59.1 billion cubic feet per day, or a year-over-year increase of 4.6%.

Despite the weak gas price environment, drilling activity has remained incredibly resilient. Exploration and production companies continue to drill through the low pricing environment as production is finding support from hedges, held-by-production provisions (i.e., lease stipulations that require drilling), joint venture-financed drilling, and liquids-enhanced wells. We are bearish on the North American natural gas market and expect prices will average $4/mmBtu for the year, assuming 30-year normal weather and no hurricane-related production loss.

As natural gas stays competitively priced relative to oil and coal, we are seeing a response on the demand side. The US industrial sector became more gas intensive in 2010. In the power sector, coal-to-gas substitution is becoming more pervasive as gas prices declined relative to coal. Indeed, gas demand experienced a strong rebound in 2010, with industrial and power gas demand up 7.1% and 7.5%, respectively. Nonetheless, the rebound in gas demand was entirely overwhelmed by the production increases; inventories are comfortable today, despite significantly colder-than-normal winter weather.

The ability of gas producers to tap into a new set of previously unavailable resource (i.e., unconventional gas) and bring down per-unit production costs through better technology has shifted the supply curve lower. We do, however, believe a stronger demand response is potentially possible. As more stringent Environmental Protection Agency rules come online, the power sector will retire a significant amount of coal-based units (we model 10GW per year retirements after 2015) and demand more gas-based generation. As US and Canadian liquefaction projects gain more traction and become a reality by 2015 (which we assume in our base case, Kitimat), North American gas prices will potentially, gradually, become more connected to global gas prices.

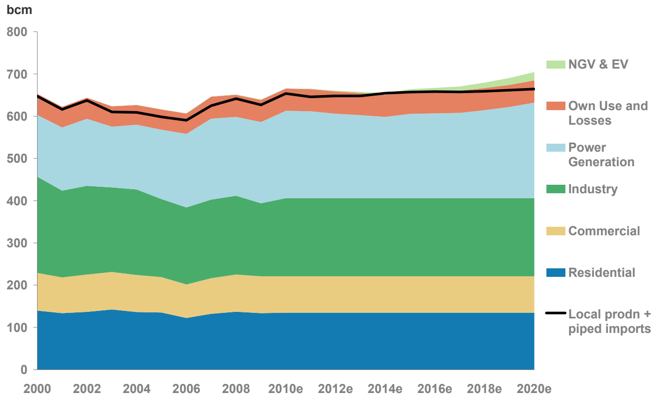
US Gas Demand: Modest Long-Term Growth Ahead

We model US gas demand using the same approach as for Europe, by major consuming segment, with key scenarios around power generation (renewables, coal, nuclear, oil, gas) and GDP. In our base case our forecasts imply 0.6% per year gas demand growth out to 2020 as a result of modelling (exhibit 68):

- Flat residential and commercial demand;
- Flat long-term industrial demand (as efficiencies improve but as industry is attracted back onshore due to low gas prices). There is a near-term (2-3 years) risk that as a direct consequence of low prevailing Henry Hub prices, industrial demand could exceed our longer-term expectations, but this is not our base case; and
- Slowly rising power generation demand as discussed below.

Exhibit 68

US Gas Demand: Modest Growth to 2020 (to 705bcm, or 68bcf/d)



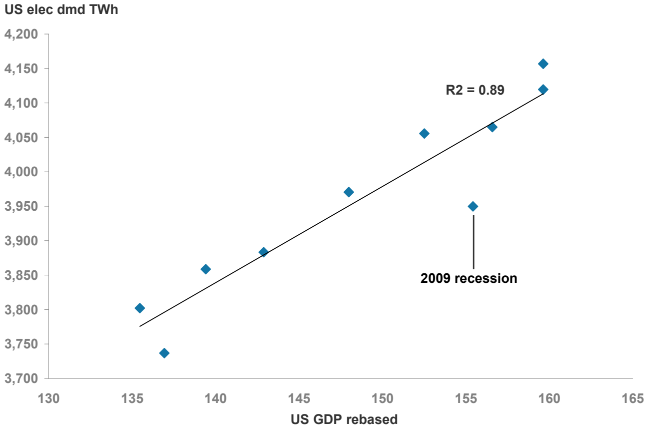
Source: EIA, BP Stat Review, WMAC, Cera, Morgan Stanley Research estimates (e)

Power Generation: Wind and Solar to Continue Taking Market Share, Gas to Benefit on Coal Retirements

We model overall power generation demand as a function of US GDP forecasts (long run 2.6%, International Monetary Fund) and use the strong historical relationship between the two as a basis for our forecasts (exhibit 69).

Exhibit 69

A Strong Relationship Between US GDP and Total Electricity Demand

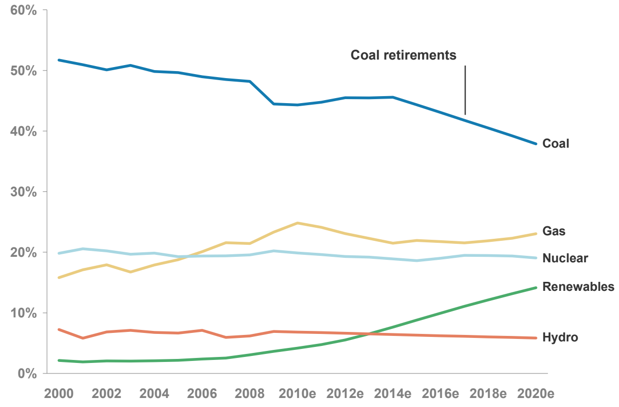


Source: IMF, EIA

We then decide how the power generation demand forecasts might be met from existing and future gas, coal, nuclear, hydropower, and wind/solar capacity, net of expected retirements. We include known new CCGT, net new coal and nuclear plants, and use Morgan Stanley's clean energy team forecasts for new wind and solar capacity. By assuming that nuclear and renewables will continue to be run on a priority basis and that EPA rules (or CO_2 legislation) will not drive material coal retirements before 2015, we are left with a net implied demand for TWh from gas-fired plants. The result is shown in exhibit 70; we expect wind and solar to continue taking market share, mainly at the expense of coal but also with some small medium-term negative impact on gas-load factors. The implication is that in this base case outlook, gas will eventually gain market share in a slowly growing power market.

Exhibit 70

US Power Generation Market Share of Each Source



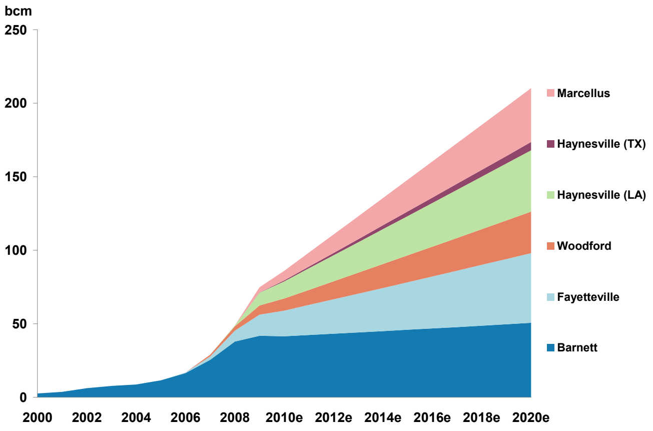
Source: EIA, Morgan Stanley Research estimates (e)

Supply: Unconventional Gas Shock to Continue

Obviously, the more-than-80bcm (8bcf/d) growth in US unconventional gas production over the last decade, and in particular the ramp-up since 2006 (exhibit 71), caught most of the world by surprise. Certainly when Qatar announced the first of six new liquefaction trains with a combined capacity of 47mtpa (or 6.1bcf/d) back in 2005 it could hardly have envisaged that the US would need, effectively, almost none of it by 2010.

Exhibit 71

US Unconventional Gas Production: A Global Game Changer – 215bcm (20.8bcf/d) by 2020e

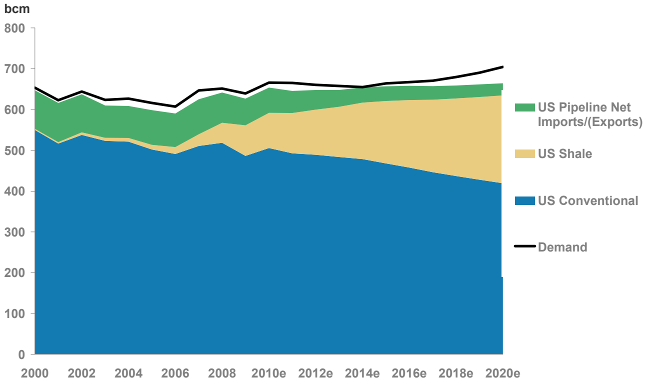


Source: IHS Energy, Morgan Stanley Research estimates (e)

On the other hand, the conventional US gas fields are in decline, and it seems very unlikely that any future discoveries can reverse this trend. Putting our forecasts for conventional, unconventional, and net-piped gas imports together, we conclude that overall supply (ex-LNG) of gas in the US will likely be almost flat over the next 10 years. The implied slight shortage of LNG for most of the next 10 years in exhibit 72 is so small in scale that it is basically telling us that the US is likely to stay self sufficient, apart from a relatively small (and shrinking) Canadian piped gas imports.

Exhibit 72

US Unconventional and Conventional Production and Piped Imports



Source: EIA, BP Stat Review, WMAC, Cera, Morgan Stanley Research estimates (e)

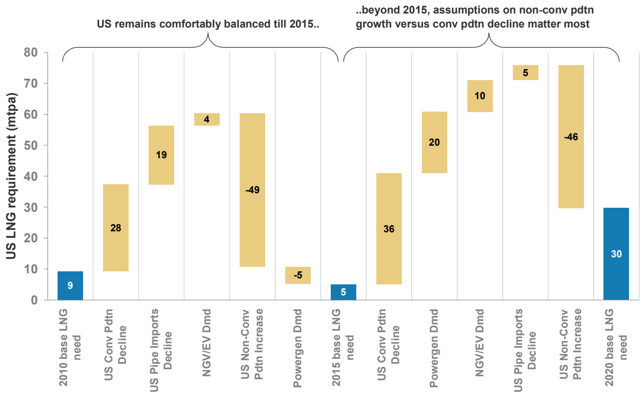
US LNG Balance: Lots of Moving Parts, but Not a Lot of Change in the Next 10 Years

We forecast very little net change in the need for LNG imports into the US over most of the next 10 years. However the path to the flat profile has numerous moving parts. As exhibit 73 shows, in our base scenario we expect:

- Conventional gas production declines will be more than offset by unconventional gas increases;
- The impact of power generation on overall incremental gas demand will be relatively small due to flat modest power generation demand growth that to a large extent can be met by a rapidly growing renewables capacity base; and
- Despite expected low Henry Hub prices driving us to assume 8% penetration of NGV new vehicle sales by 2020, the implied substitution effect for gas is still relatively immaterial (18bcm, or 1.7bcf/d by 2020).

Exhibit 73

US Implied LNG Imports 2010e–2020e



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

LNG Scenarios

With a base case of gas self-sufficiency in the US, it is tempting to conclude the country will have no impact on global LNG markets, but this would be tempting fate. Clearly, unconventional gas *has already* had a massive impact on global LNG markets, and there are various scenarios we can see that could once again affect global gas markets.

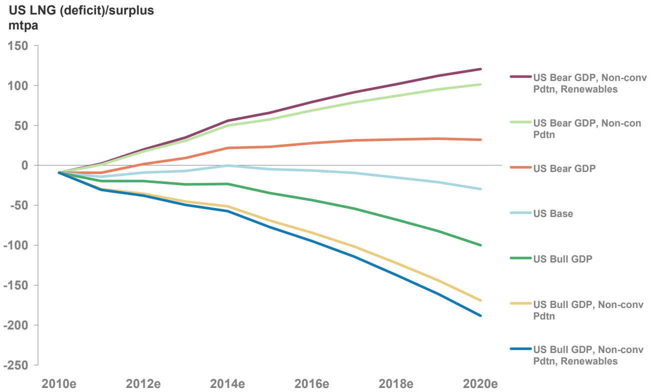
- **GDP growth,** i.e., gas-fired power generation demand. We assume 2.6% US long-term (after 2015) GDP growth in our base case and flex this assumption by +/- 150bps in the bull and bear scenario.
- **Unconventional gas production growth.** In our base case, we estimate US unconventional gas has a CAGR of about 10% to 215bcm (20.8bcf/d) by 2020 from 86bcm in 2010. In our bull and bear scenario, we flex this assumption by +/- 20%.
- **Renewables construction.** In our base case, we use Morgan Stanley's Clean Energy team's forecasts of 160GW of new renewables capacity in the US between 2010e-2020e. In our bull and bear scenario, we flex this assumption by +/- 25%.

Significant Variance Around Our Flat Base Case

The impact of these scenarios is a significant range of possible outcomes around our base case, as shown in exhibit 74. Different GDP or unconventional gas scenarios can easily tip the US into being either a major importer of LNG or, theoretically at least, an LNG exporter.

Exhibit 74

US Implied LNG Import Scenarios: GDP and Unconventional Gas Scenarios Could Change the Game Again



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

There are several US liquefaction projects proposed (exhibit 75), and this highlights a risk to our base case—that the US may add enough liquefaction capacity to add further to the medium-term global LNG oversupply we already see persisting until 2015.

There is also a material *domestic* arbitrage opportunity relative to more than $100/bbl gasoline. Instead of investing with a view of persistently high Henry Hub-Global LNG price differences, players may take a closer look at domestic opportunities such as gas to liquids (GTL) and/or natural gas vehicle infrastructure build-out. Indeed Sasol has recently entered into two Montney basin Canadian shale plays with Talisman with a view to constructing a possible 96kb/d GTL plant.

Exhibit 75

Proposed North America Liquefaction Projects

Project	Company	Start Year	mtpa	No. of trains	Status/Comments
Sabine Pass, Texas	Cheniere	2015e	3.5	1	Application filed with FERC; MoUs for 9.8mtpa of supply from 2015 (Feb 2011)
Kitimat, Canada	Apache, EOG	2015e	9	2	FID expected 2011
Port Freeport, Texas	Freeport LNG	2015e	10.7	4	Proposed. Waiting on FERC. No FID target date as yet.
Cove Point, Maryland	Dominion	2015e	tbc	tbc	Dominion announced plans to construct a LNG export terminal in Cove Point by 2015. (Jan 2011)

Source: Company data. Note: Our base case LNG supply numbers excludes Freeport and Cove Point since the projects are still in MoU stage.

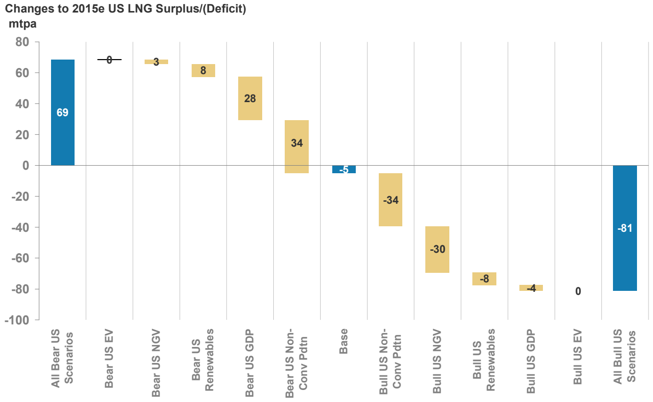
Unconventional and GDP Assumptions Are the Key Risks to Our Forecasts

Looking at 2015, exhibit 76 shows how more aggressive unconventional gas (plus 20% from base) and conservative GDP (1.1% vs base of 2.6%) assumptions dominate our US bear case (i.e., would potentially push the US into surplus gas that could possibly be exported). On the other side, the major factors that could make the US into a more significant importer of LNG are again unconventional assumptions (e.g., legislation that slows down the exploitation) and/or a surprise in the form of sharply increased uptake of natural gas vehicles.

In practice the biggest wildcard for US gas demand is policy. The US is just now adjusting to the reality of a plentiful, low cost supply base for natural gas. While the profit incentive for LNG export, conversion projects (GTL), or other fuel switching exists today, the policy backdrop remains a key factor to watch. While we do not expect immediate action, Washington could materially alter our demand expectations on a 5-10 year view via the support of switching towards natural gas in any of the powergen, industrial, and transportation sectors.

Exhibit 76

Scenarios Around 2015e US Base Case: GDP, Unconventional Pdtn Assumptions Matter Most



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

China: How Will Its Huge Gas Demand Growth Be Met?

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Significant gas demand growth. We forecast China's gas demand to grow by over 200bcm by 2020. In LNG terms, this is the equivalent of the output from 18 Qatar trains, or 65% of current global LNG capacity.

Equally strong supply growth. We forecast local production to continue to grow at 13% per year until 2015, and growing piped gas imports from Kazakhstan will also help. Therefore, we do not expect any material pickup in LNG demand in China during the next five years.

After 2015 we expect to see strong LNG demand growth. We expect local production growth to moderate eventually to 8% in our base case. We then expect a widening gap between gas supply and demand to emerge, which in our base case would need to be filled by LNG. We expect China's LNG demand to rise by 65mtpa between 2015 and 2020.

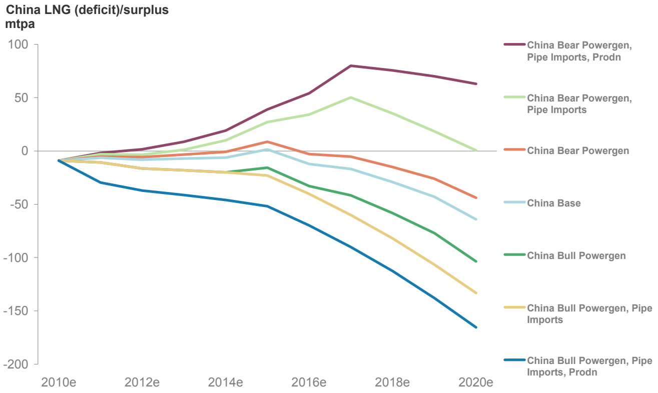
What could change? The most important swing factors in our analysis are pipelines from Russia, China GDP (and hence power generation demand), and the performance of the three main producing onshore basins – Ordos, Tarim, and Sichuan.

Natural gas vehicles play a minor role in China gas demand today, but as a solution to growing pollution concerns and rising global oil prices, there is significant gas demand upside in our bull case for NGVs.

Implications. With the investments we model today, we see a major growth in China LNG demand looming after 2015. To address this we expect to see one or more of: 1) the Russian Altai export pipe get FID in the next year; 2) further regulated gas price rises to encourage upstream gas investment, where PetroChina, Sinopec, and CNOOC will likely continue to dominate; 3) continued IOC interest in gaining local upstream access, where possible; and 4) potentially strong NGV uptake growth.

Exhibit 77

China Implied LNG Import Scenarios



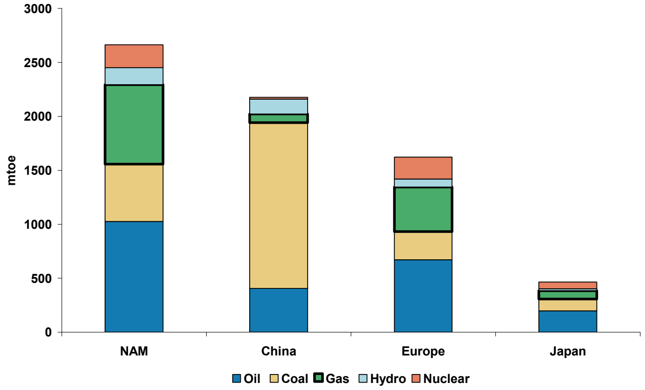
Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Gas demand: Fast Growth From a Relatively Low Base

Coal dominates the mix of energy consumption in China, and this will likely remain the case for many years to come, simply because the country's remaining domestic coal resources are so huge—especially when compared to its domestic oil and gas reserves (exhibit 79).

Exhibit 78

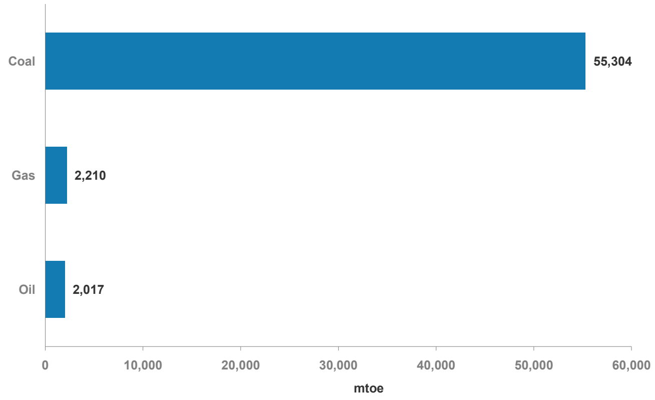
Energy Demand Split 2009: Gas Is a Small Part of China's Energy Mix vs. Europe and North America



Source: BP Stat Review 2010

Exhibit 79

China Reserves, Million of Tons of Oil Equivalent

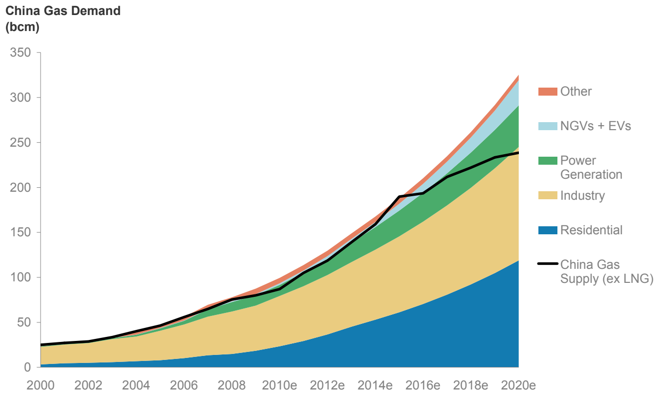


Source: BP Stat Review

However, although gas is, and will probably stay, a relatively small part of the energy mix in China, we think the sheer scale of the country's economic growth still leaves more than 200bcm of gas demand growth over the next 10 years (exhibit 80-81).

Exhibit 80

China Gas Demand – Industrial and Residential Sector to Dominate; 200bcm+ Demand Growth by 2020

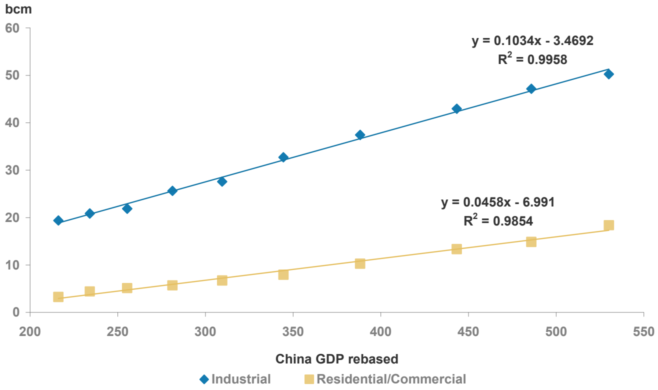


Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

The IMF and Morgan Stanley expect high Chinese GDP growth to persist for the foreseeable future, and we base our gas demand modelling on an assumption of 8% GDP growth (in-between China's target of 7% for "sustainable growth" and IMF's 9.5% LT forecast) out to 2020. The historical correlation between Chinese GDP and both industrial and residential/commercial gas demand is strong (exhibit 82), and we use this relationship to model future gas demand for these subsectors.

Exhibit 81

High Correlation Between Chinese GDP and Industrial and Residential/Commercial Gas Demand



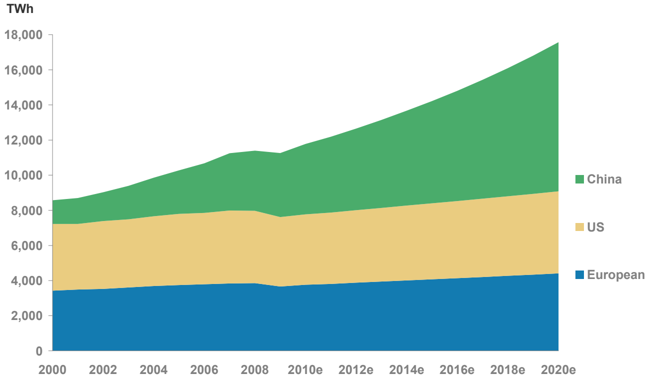
Source: BP Stat Review, WMAC, Morgan Stanley Research estimates (e)

China Gas Demand in the Power Segment

For gas demand in the power generation segment, we model the overall TWh demand as a function of GDP and then consider how the demand will be met from a combination of coal, gas, nuclear, hydropower, and other renewables. With a forecast of 8% long-term GDP growth, it is not surprising that we expect a material increase in the country's electricity demand, to the extent that by 2020 we forecast its TWh needs will exceed those of both the US and Europe combined (exhibit 83).

Exhibit 82

China to Dominate Global Electricity Demand Growth

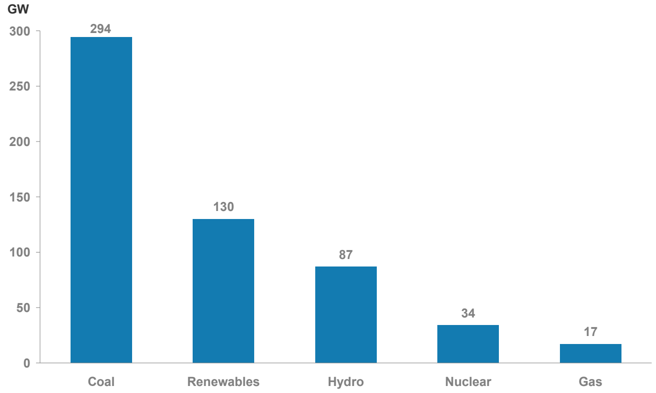


Source: WMAC, CERA, Morgan Stanley Research estimates (e)

In terms of where these incremental TWh will come from, coal will obviously continue to dominate, but increased gas power generation also has an important role to play, as does nuclear and renewables (exhibits 84 and 85).

Exhibit 83

The 12th Five-Year Plan: Gas Is Far From the Lynchpin of the Energy Strategy



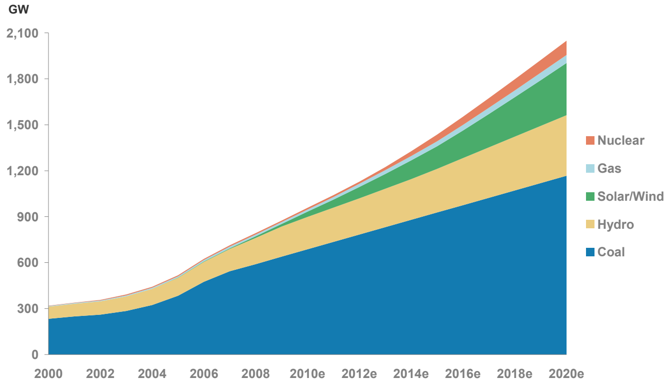
Source: Chinese 12th National 5-Year Plan

For China, the power supply dynamics are different from what we see in the US and Europe. CCGT plants are needed to some extent because although China is long coal, transporting enough coal from the fields in the northeast and northwest to where it is needed most (Shanghai and the southeast) is increasingly challenging, and the national grid still has major bottlenecks that will take several years to resolve.

New gas-fired capacity is likely to be linked to specific south-east or east regas terminals or dedicated onshore stranded gas fields and will run no matter what the coal-gas price differential is because the regulated power price is set in such a way that cheaper coal effectively subsidises the CCGT operations that receive permission to be built.

Exhibit 84

Chinese Power Generation Capacity by Fuel, 2000-2020e



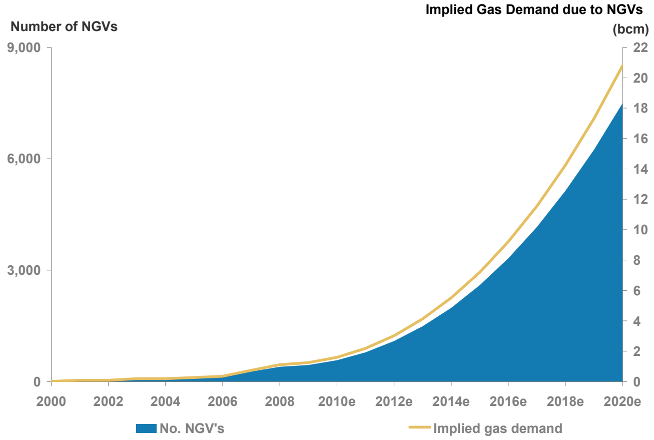
Source: WMAC, CERA, Morgan Stanley Research estimates (e)

NGV Demand Outlook: a Potential Source of Another 20bcm of Gas Demand

A source of incremental gas demand in China is natural gas vehicles, whether CNG cars or LNG trucks (exhibit 86). Although our work indicates this will not be a game changer (at least by 2020) in terms of the global gas balance, if we make the assumption that high oil prices, pollution control measures, and potential diesel shortages drive an NGV penetration rate of 5% for new vehicle sales by 2020 (from near zero today), then we see 7.5 million NGVs on Chinese roads within 10 years (from about 500,000 today). The NGV industry is potentially attractive and high-growth in its own right, and the outlook for Chinese NGV implies an extra 20bcm of local gas demand.

Exhibit 85

Base Case NGV Fleet Increase and Implied Gas Demand



Source: IANGV, Morgan Stanley Research estimates (e)

Note that even with such an exponential growth in NGVs, the total NGV fleet would only represent 3.5% of all cars and trucks.

Supply: Ample Resources, but Infrastructure and Pricing Challenges

China is a mature oil province but has significant gas reserves in a relatively immature gas sector. Gas power generation and home heating have never really taken off, simply because coal has always been so much more readily available and only recently are the required gas trunk lines and local distribution networks receiving the massive investment required.

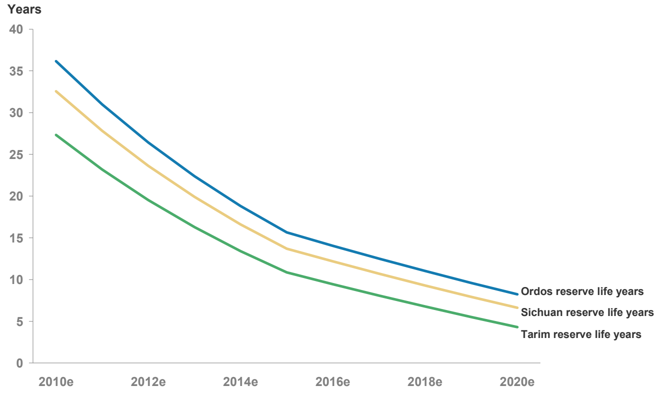
On the supply side, we base our domestic gas production forecasts on our Asian team’s forecasts until 2015, and then run at lower growth rate assumptions (approximately 4%) for the major basins (Ordos, Sichuan, and Tarim) until 2020. This puts us close to the forecasts of Wood Mackenzie LNG's service, which in turn is based upon 2010 analysis that includes yet-to-find conventional and unconventional gas resources (exhibit 87).

This base case of a moderation in local gas production growth after 2015 is still consistent with our Asian team expectations for continued double-digit gas production growth for PetroChina, Sinopec, and CNOOC. In the context of this global gas report, we are sure that these three companies will indeed see continued strong gas growth, but we are unsure whether all of this growth will come from yet-to-find domestic gas or whether a portion will come from the companies' investing in overseas integrated LNG or even into integrated Russian piped gas export projects. Either way, China will need a lot more gas and PetroChina, Sinopec, and CNOOC will dominate its incremental supply.

Our base-case-implied, overall forecast growth of 13% per year to 2020 requires further major internal pipeline infrastructure to be built, such as the West-East 3 trunkline (exhibit 88). However, given the success of the three major domestic players in delivering 13% production CAGR over the last 10 years and the successful pipeline construction to date (West-East 1, West-East 2, Sichuan-Shanghai, etc.), we are comfortable with our forecasts, which in practice are almost in line with the key companies' publically stated targets for 2015.

Exhibit 86

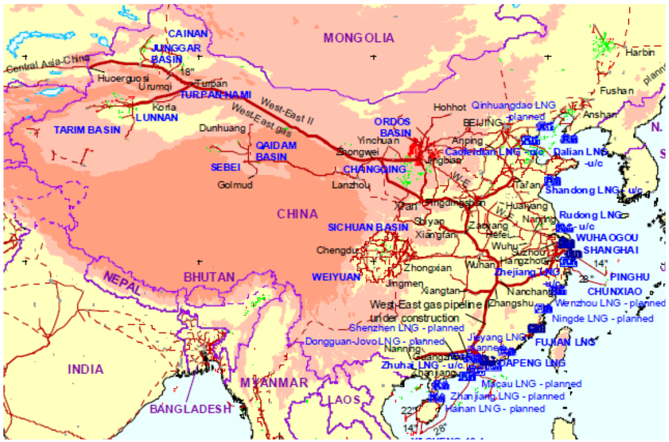
Production Forecasts Drive a Falling Reserves Life That Implies That More Gas Reserves Will be Found



Source: Wood Mackenzie, Morgan Stanley Research

Exhibit 87

China Gas Transport and Distribution: Much Construction to be Done

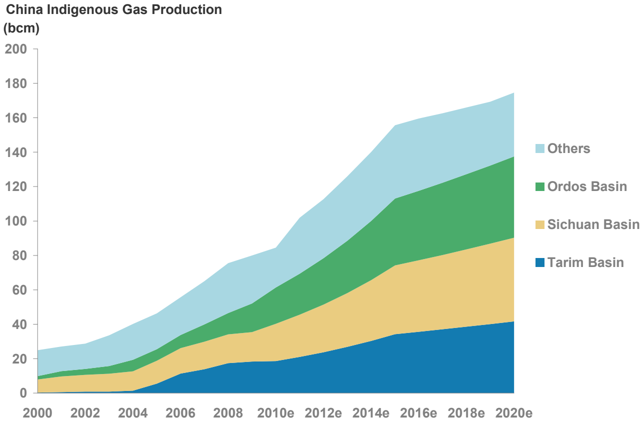


Source: Wood Mackenzie

There is in practice a lot of potential variability in our China domestic gas production forecasts (e.g., deregulation of prices and acreage rights would probably drive a very significant surge in investment), but we try to capture this uncertainty in our scenario modelling, where we consider a +48% to -25% range around our base local production assumptions.

Exhibit 88

China Indigenous Production Base Case Forecast



Source: WMAC, Morgan Stanley Research estimates (e)

Unconventional Gas: There May Be Lots Of It, But Conventional Should Get Priority

Much is commented on the potential for unconventional gas production in China. Our opinion is that the overriding consideration has to be that China has significant amounts of as-yet underdeveloped conventional gas reserves, and these lower-cost resources will be developed first (exhibit 89).

However, IOCs have very limited access to onshore conventional gas, hence the interest in unconventionals: it is the only way in. We assume that several years of reservoir study are required but note that CNOOC, Sinopec, and, in particular, PetroChina have the acreage, engineers, and rigs to accelerate this process, if they become sufficiently motivated to do so by rising local regulated gas prices (exhibit 90).

Exhibit 89

IOC Interest in Chinese Unconventional Oil/Gas Plays

Date	Buyer	Seller/ Partner	Type	Comment
Jan-11	BP	CNOOC	Deepwater	Exploration of deepwater Block 43-11
Sep-10	BP, Chevron	Devon Energy	Deepwater	Blocks 53-30 64-18 and 42-05
Jul-10	BP	PetroChina	Coalbed Methane	Development of Shaerhu CBM block
Mar-10	RD Shell	CNPC	Tight Gas	Development of Jinqiu Block
Aug-06	RD Shell	Government of China	Oil Shale	Agreement to jointly develop oil shale resources in Jilin Province
Jul-06	BG	CNOOC	Deepwater	Two PSCs in western South China Sea

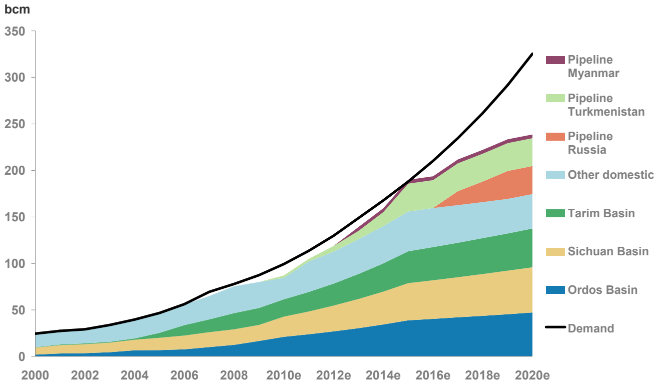
Source: IHS Herold

Piped Gas to Lessen the Potential Gas Shortfall

China does not have to rely only on local gas production or LNG imports; it neighbours Russia and Kazakhstan (and indirectly, Turkmenistan), which are long gas and eager to develop new markets. We expect strong growth over the coming decade as the Central Asia China gas pipeline (Turkmenistan to Western China via Uzbekistan and Kazakhstan) expands its capacity to 40bcm. The Altai gas pipe from Russia has been the subject of long negotiations, but we expect to see FID this summer and for this project to then move forward at pace. It could supply another 30bcm by 2016 and then, in our bear scenario, an additional 30bcm via an eastern route.

Exhibit 90

China Local and Piped Gas Supply: Growing Fast but Still Leaves a Growing Gap After 2015

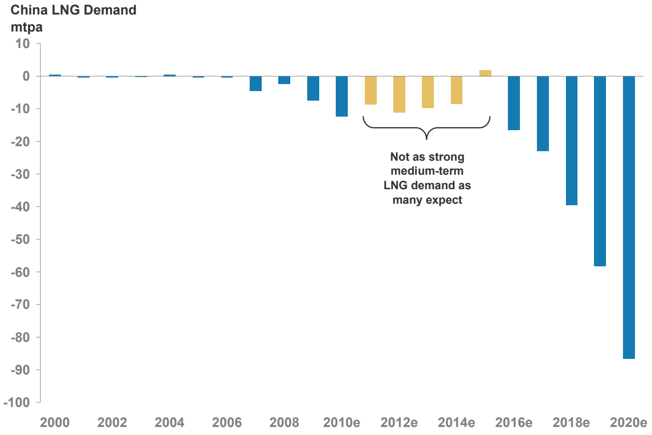


Source: WMAC, Morgan Stanley Research estimates (e)

The net result of our China gas supply (local and piped) versus demand work is that as shown in exhibits 91 and 92; we expect China's base case LNG requirement to be relatively flat until 2015, as local supply growth copes with robust gas demand growth.

Exhibit 91

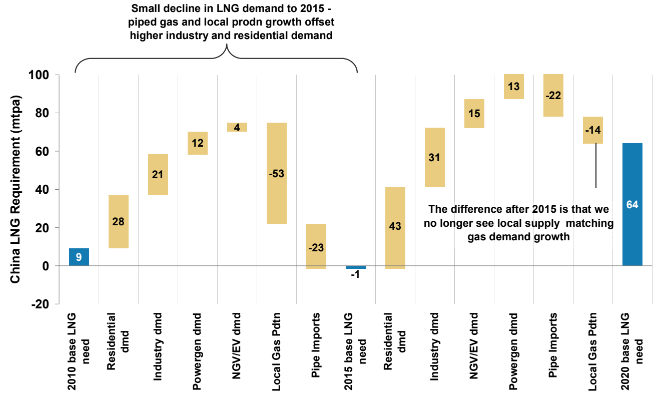
China Implied LNG (demand) to 2020e – Relatively Low Until After 2016



Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Exhibit 92

China 2010-2015-2020 LNG Demand Build-Up



Source: Morgan Stanley Research estimates

The key moving parts out to 2015 are shown in exhibit 93:

- Residential (more than 18% CAGR) and industrial (more than 8% CAGR) and gas demand growth to be strong.
- Power generation gas demand growth to average 14% CAGR but to be relatively unimportant in absolute terms.
- Local production balances the picture until 2015, but thereafter the risk is that local production growth cannot sustain the double-digit rates and a growing need for LNG emerges.

LNG Scenarios

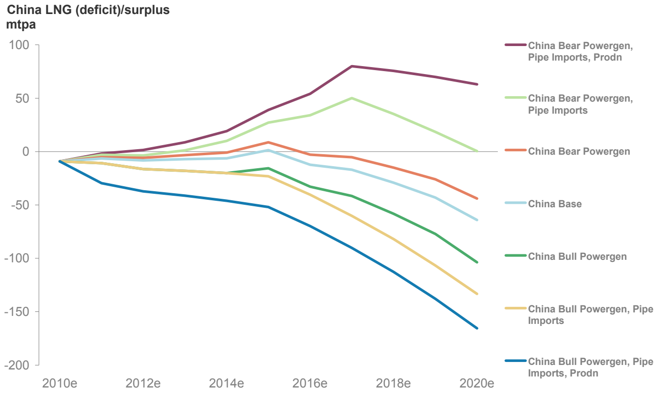
A wide range of possible outcomes is inevitable, given the growth profile of China's energy demand and the variety of choices it can make in how to meet that demand. We try to reflect uncertainties by considering what we believe are the most important swing factors for the overall Chinese gas supply/demand and hence LNG outlook:

- **GDP growth scenarios.** Drive industrial, residential, and power generation demand. We assume 8% long-term GDP growth in the base case. We flex this assumption by +/- 250bps in the bull and bear scenario.
- **Pipeline imports.** In our base case, we assume 30bcm imports from Turkmenistan and another 30bcm via the Altai pipeline from Russia. In our bear case, we include 60bcm imports from Russia by 2020.
- **Local production.** We consider the profile of the three major basins Ordos, Tarim, and Sichuan. Around our base case we run a bear case that is about 50% above our base by 2020, and in our bull scenario we reduce local gas production by 25% relative to our base.
- **Transport.** The potential impact of natural gas vehicles and/or electric vehicle uptake.

Exhibit 94 shows the impact these scenarios have on our estimate of China's LNG need (or indeed, surplus). The scenarios that give rise to a surplus do not mean we seriously believe that China would build liquefaction and start exporting LNG in these cases, it is just an indication of how the industry stresses would move.

Exhibit 93

China Implied LNG Import Scenarios

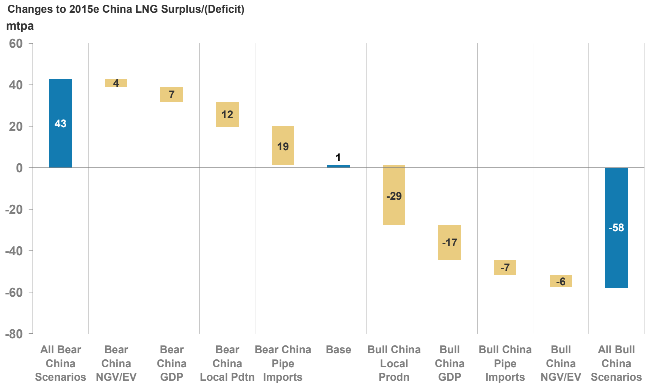


Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

As to the assumption changes that matter most, we show the 2015 sensitivity in exhibit 95 below. We think Higher Central Asian Pipeline imports are the most significant threat to LNG import needs, followed by higher-than-expected local gas production growth. On the bull side, it is GDP growth and disappointing local production that matter most. The impact from NGV/EV fleet expansion is relatively minor in all scenarios.

Exhibit 94

Bear-bull: Changes to 2015e China Base Case LNG Imports



Source: WMAC, BP Stat Review, Morgan Stanley Research estimates (e)

India: Local Gas Demand to Outstrip Local Supply

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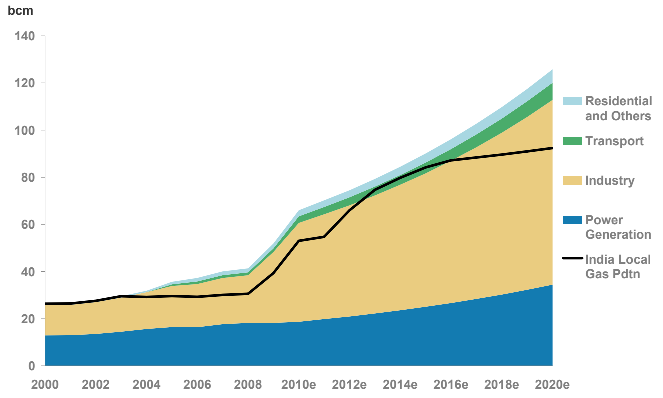
Gas Demand

We model Indian gas demand by major subsector, power generation, and industry (mainly petrochemicals and fertilizers), based on IMF GDP forecasts, and for the much smaller transport and residential demand segments we use a simple growth factor.

The outcome is that we expect Indian gas demand to continue growing robustly, at an average rate of almost 7% to 2020, high but slightly below the 10% per year demand growth recorded over the last 10 years (exhibit 96).

Exhibit 95

India Gas Demand by Segment: 7% Implied CAGR out to 2020



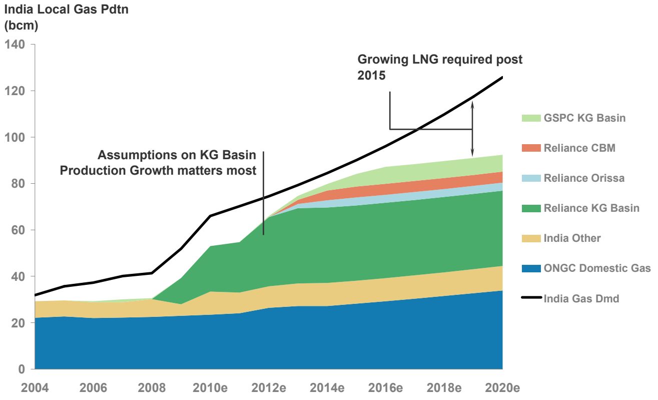
Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Local Supply

Indian gas production has grown strongly over the last two years on the back of Reliance's KG basin development (exhibit 97). We expect this field to contribute to further growth in 2011-12 before reaching a 2013 plateau that, given the vast remaining gas resources in the basin (14tcf for K6 block alone), we expect to be maintained until at least 2020.

Exhibit 96

India Gas Supply: Huge KG Basin Discoveries a Game Changer



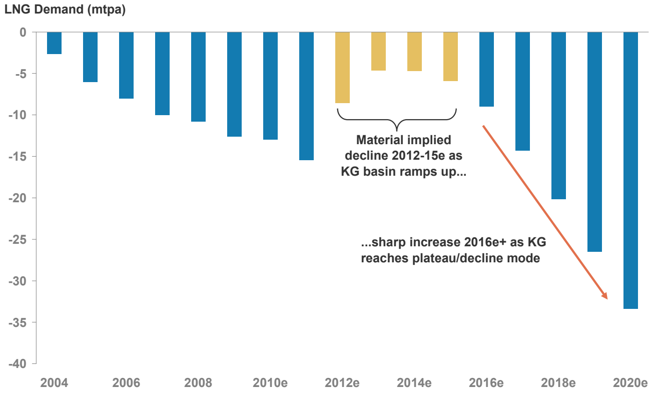
Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (e)

Implied LNG Demand

The slowdown in KG basin production growth along with continued GDP driven demand inevitably leads us to forecast a growing need for LNG imports (exhibit 98).

Exhibit 97

India LNG Demand to Grow by 20bcm by 2020



Source: WMAC, BP Stat Review, Morgan Stanley Research estimates (e)

Australia: Qatar’s Big Brother?

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We forecast that Australia will add significant new liquefaction capacity over the coming decade and will double its global LNG market share from 9% today to almost 20% by 2020 in our base case (from 19mtpa to 74mtpa).

Key projects in our base case are the conventional offshore Gorgon (Chevron, Exxon Mobil, RD Shell), Wheatstone (Chevron, Apache) and Pluto1 (Woodside), and the coal bed methane QCLNG (BG), GLNG (Santos, Petronas, Total) and APLNG (Conoco, Origin, Sinopec) onshore developments.

New projects sanctioned. Given the post-2015 global LNG shortages that are implied by our base case modelling, there is the potential for many of Australia’s proposed 84mtpa of additional liquefaction projects to also be sanctioned in the coming years.

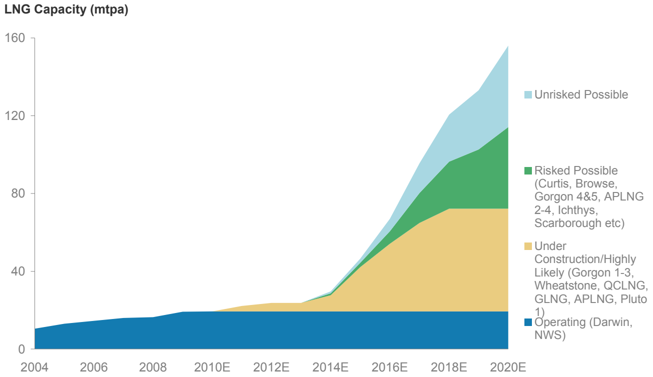
Upside supply projects are dominated by Chevron, Woodside, BG, RD Shell, Exxon and Total. Shell’s Prelude project would be a major milestone in that it would be the world’s first floating liquefaction facility (FLNG).

BG and Chevron are building major new liquefaction projects and are perfectly poised to expand these and potentially capture the longer-term LNG opportunity by announcing further projects and/or expansions.

In the context of contribution to the global LNG net balance, Australia is all about existing and future LNG supply. It already supplies 19mtpa (9% of global capacity), mostly to Asian markets, and this is set to rise to at least 72mtpa by 2020e (which will be 21% of global capacity). Over that period the country will be by far the largest new contributor to global LNG supplies, and with huge onshore and offshore gas resources still available for further projects, we think there is every chance that this capacity could rise yet further (exhibit 99).

Exhibit 98

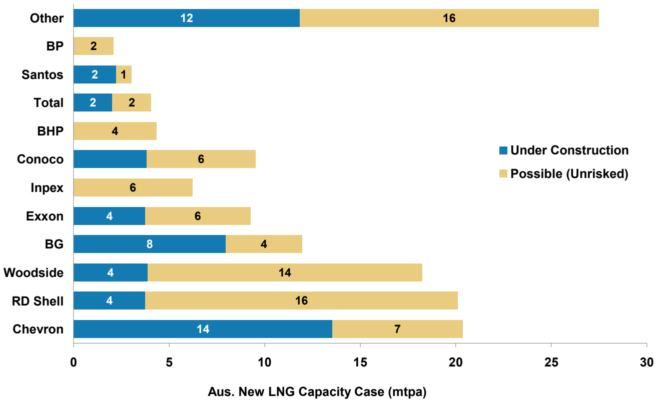
Australia: LNG Capacity to Reach 72mtpa by 2020 From 19mtpa in 2010



Source: WMAC, Morgan Stanley Research estimates (e). Note: ‘CORE’ = Operating + Under-Construction/Highly Likely projects.

Exhibit 99

Chevron, Woodside, RD Shell, and BG Have Taken a Lead Role in Australia’s LNG Expansion Projects



Source: WMAC, Morgan Stanley Research estimates

Core New LNG Projects Equal 53mtpa LNG Capacity

Gorgon (Chevron 47%, Exxon 25%, RD Shell 25%, Other 3%). Construction of this 3 x 5mtpa LNG project is under way. with first gas expected in 2015. Continued exploration success in recent years has added multi-Tcf of reserves in the Greater Gorgon petroleum licenses and underpins future expansion projects (two additional trains under consideration). Currently, 93% (13.9mtpa) of the LNG from Gorgon has been contracted: PetroChina (4.3mtpa), Osaka Gas (1.6mtpa), Petronet LNG (1.5mtpa), and others (7.6mtpa) (exhibits 100-101).

Exhibit 100

Australia Base Case LNG Projects

Project	Partners	Startup	Size (mtpa)	No. of Trains	FID Status	Field Type
On-Stream						
Burrup (NWS Train 1-5)	Woodside, BHP, BP, Chevron, Shell, MIMI	1989 / 04	17	5	Approved/Operational	Offshore
Darwin LNG	Conoco, Santos, Inpex, ENI	2006	4	1	Approved/Operational	Offshore
Existing LNG Capacity			**21**	**6**		
New Projects						
Gorgon 1-3	Chevron, Exxon, Shell	2015E	15	3	Approved/Under-Construction	Offshore
Gladstone-APLNG	Conoco, Origin Energy, Sinopec	2015E	9	2	FID expected mid 2011	CBM
Wheatstone	Chevron, Apache, Kufpec, TEPCO	2016E	9	2	FID in 2011/12e	Offshore
Gladstone-QCLNG	BG	2014E	9	2	Approved/Under-Construction	CBM
Gladstone-GLNG	Santos, Total, Petronas	2014E	8	2	Approved/Under-Construction	CBM
Pluto1	Woodside, Tokyo Gas, Kansai Electric	2011	4	1	Approved and 95% complete	Offshore
Core New Capacity			**53**	**12**		
Australia Base Case LNG Capacity			**74**	**18**		

Source: WMAC, Morgan Stanley Research estimates (E)

Prices: Woodside A$42.20, Origin Energy A$15.66

Wheatstone (Chevron 75%, Apache 16.3%, Kufpec 8.7%). The target for FID is 2011-12, with first production in 2016. Initial plans are for a two-train project with name-plate capacity of 8.6mtpa to be located at a site in Onslow, Western Australia. Currently 80% (6.8mtpa) of the LNG from Wheatstone has been contracted: TEPCO (4.1mtpa), KOGAS (1.9mtpa) and Kyushu (0.9mtpa).

QCLNG (BG 94%, Others 6%). BG approved this project in October 2010, and construction of this two-train 8.5mtpa project is now under way, with first gas expected in 2014. QCLNG represents the first LNG facility that will use coal-seam-gas (CSG) as feedgas. Currently 85% (7.2mtpa) of the LNG from QCLNG has been contracted: CNOOC (3.6mtpa), BG (2.0mtpa), Tokyo Gas (1.2mtpa), and others (0.4mtpa).

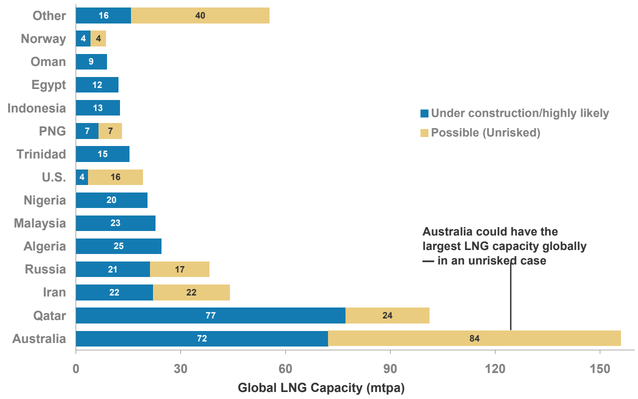
GLNG (Santos 30%, Total 27.5%, Petronas 27.5%, Kogas 15%). The project partners took FID for this project in January 2011 and the plan is for a two-train 7.8mtpa LNG project, with first gas expected in 2014. Like QCLNG, the GLNG project will also use CSG as feedgas. Currently 90% (7mtpa) of the LNG from GLNG has been contracted: KOGAS (3.5mtpa), Petronas (3.5mtpa).

APLNG (Conoco 42.5%, Origin 42.5%, Sinopec 15%). The target for FID is mid 2011, with first production in 2015. Initial plans are for a 2 x 4.5mtpa LNG facility that will use CSG (from the Bowen and Surat basins) as feedgas. Currently Sinopec has signed a preliminary agreement to take up to 4.3mtpa of LNG over a 20 year period.

Pluto - Train 1 (Woodside 90%, Others 10%). Phase 1 construction for the 1 train 4.8mtpa Pluto LNG project is 95% complete and first gas is expected in 2011. Currently 78% (3.8mtpa) of the LNG from Pluto1 has been contracted: Kansai (2mtpa), Tokyo Gas (1.8mtpa).

Exhibit 101

In Our Bear Case, Australia Is Set to be the Largest LNG Exporter by Some Distance



Source: WMAC, Morgan Stanley Research estimates

Bear Case Is Another 84mtpa of Unrisked New Capacity

Our bottom-up analysis indicates to us that whilst the world will remain long LNG for the next five years, thereafter we face a relatively rapid tightening and unless something changes, the world will be short LNG after 2015. The sensitivity work in this report highlights some of the potential factors that could change this outlook – Chinese local production, even more renewables construction, and/or lower GDP than expected would all make a difference. However, the most obvious path to preventing the likely post-2015 tightness is, of course, to build more liquefaction capacity than what we include in our base case assumptions. Australia stands out as the most obvious place for this to happen (exhibit 102).

In our bear supply case for Australia LNG we see the potential for another 84mtpa (unrisked, over and above our 'core' LNG projects) by 2020. This would leave Australia with a total liquefaction capacity of 156mtpa; it would be the largest LNG exporter by some distance (exhibit 103).

Exhibit 102

Australia Possible New LNG Projects: Additional 84mtpa of Unrisked Capacity by 2020e

Possible Projects	Partners	Startup	Unrisked Capacity (mtpa)	No. of Trains	Field Type	Status/Comments
Shell / Petrochina	Curtis Island	2016E	16.0	4	CSG	FEED in 2011, FID by 2012e
Browse	Woodside, Chevron, BHP, Shell	2017E	12.0	3	Offshore	Aus. Govt set deadline of FEED by 2011 and FID by mid-2012
Gorgon 4 & 5	Chevron, Exxon, Shell	2018E	10.0	1	Offshore	FID possibly after trains 1-3 come on-stream
APLNG-trains 3-4	Conoco, Origin Energy	2018E	9.0	2	CSG	FID in mid 2011e.
Ichthys	INPEX	2017E	8.4	2	Offshore	No LNG sales contracts signed thus far. FID in end 2011e
Scarborough	Exxon, BHP	2020E	6.0	2	Offshore	Technical/Commercial difficulty. FID in 2012e/2013e
Pluto2	Woodside, Tokyo Gas, Kansai	2014E	4.3	1	Offshore	FID possibly after train 1 comes on-stream
Pluto3 or others	Woodside, Tokyo Gas, Kansai	2016E	4.3	1	Offshore	FID possibly after train 2 comes on-stream
Gladstone-Curtis LNG	BG-train 3	2017E	4.3	1	Offshore	FID possibly within 12-18 months
Sunrise-FLNG	Woodside, Conoco, RD Shell	2020E	4.0	1	Offshore	Technical challenges. Aus. & Timor-Leste set deadline of FID by 2013.
Prelude-FLNG	Shell	2017E	3.6	1	Offshore	Environment approval received. FID by 2011e.
Bonaparte LNG	Santos, GDF Suez	2017E	2.0	1	Offshore	FID by 2014E
Australia Other Projects			83.9	21		

Source: WMAC, Morgan Stanley Research estimates (E)

Global Gas

Appendices

Appendix A: Natural Gas Vehicles

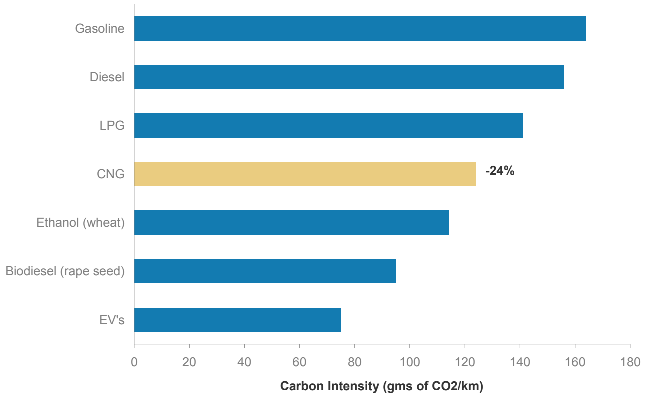
We discuss the impact of natural gas vehicles in some of the scenarios in this report, but what are they?

Natural gas vehicles come in two flavours: CNG (compressed natural gas) and LNG (liquefied natural gas). CNG vehicles are already widely used in several countries, and basically involve storing compressed gas in a special fuel tank connected to your modified gasoline engine in your normal car.

The attractions are usually 1) cheap local gas due to a regulated gas price regime (e.g., Argentina, Pakistan), and 2) a fuel with lower CO_2 intensity than oil-based products.

Exhibit 103

NGVs Cut CO2 Emissions by About 25%

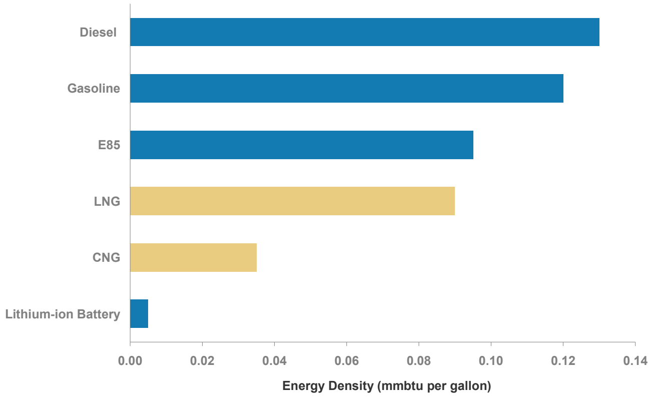


Source: California Air Resources Board, Clean Energy Fuels

The main weakness of CNG vehicles is that the energy content of even compressed gas is much lower than that of gasoline, so even after using a much bigger tank (that takes up luggage and passenger space), the range of these vehicles is much less than that of a regular gasoline-powered car.

Exhibit 104

CNG Vehicle Performance Is 60%-70% Lower Than Gasoline/Diesel



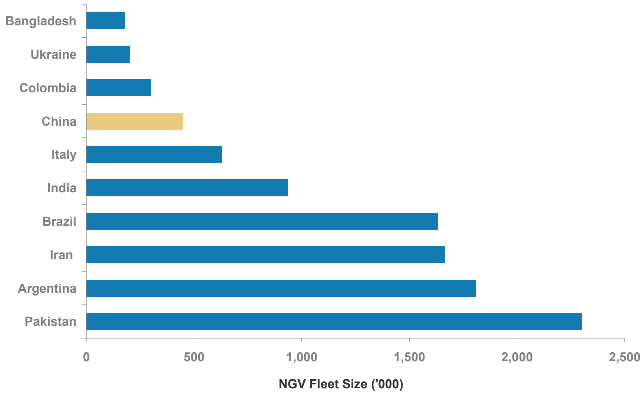
Source: IHS Cera

This energy-density weakness can be largely addressed by using LNG vehicles, with the main hurdle being infrastructure and cost of modification; basically the LNG needs to be imported into the country, then distributed via truck to the point where it will finally be stored and then used to refuel an LNG powered vehicle. The cost of modifying a large truck to run on LNG is of the order of $70,000. These may sound like major hurdles, but in a place like China, where businesses literally shut down for days due to lack of diesel and/or power generation supplies, the obstacles may well be overcome.

Where Are NGVs Being Used Today?

Exhibit 105

Top 10 NGV Users



Source: IANGV, Note: Data based on actual for 2009 as reported by IANGV

Appendix B: In Europe, Unconventional Gas Will Likely Be a Long Time Coming

There is much interest in European unconventional gas potential right now, with several IOCs having recently invested in acreage, primarily in Poland. Although the US experience was a game changer and people look for the same impact in Europe, it is far too early to say whether this is a realistic outlook or not. However, the appraisal will help to determine the economic viability (or not) of various plays, and this activity is continuing, as summarised in exhibits 106 and 107.

Exhibit 106

IOCs and Independents Are Back Pursuing Unconventional Gas Opportunities in Europe

Name	Country	Appraisal Activity
ExxonMobil	Germany and Poland	10 wells in Germany in 2010
Hess/Toreador	France	6 wells in 2010
Conoco/Lane Energy	Poland	3 wells in 2010
RD Shell	Sweden and Ukraine	3 wells in Sweden in 2010
Talisman/San Leon	Poland	plan 7 wells by 2012
PKN	Poland	plan 2 wells in 2011
Aurelian	Poland	1 well in 2010
OMV	Austria	
Total	France	
BG	France	
Marathon Oil	Poland	

Source: Elixir, Company Data

Exhibit 107

The Potential Unconventional Prize in Europe

	Potential Resource Size (bcm)	Source
OECD Europe	3000	EIA (2010)
Poland	1400 - 3000	WMAC - ARI (2009)
Austria	420 - 850	OMV - ARI (2009)
Sweden	300	ARI (2009)
Paris	1600	P10 of Toreador's 100bn boe est.
Europe Pdtn Range	10-40bcm/y	CERA - Others

Source: Company data, Morgan Stanley Research

Polish shale gas resources in particular have attracted IOC interest, in part because the country is seeking investment: The country issued 58-62 concessions in 2007-10 and there are some broad analogies between Polish shale gas reservoirs and the major US plays.

The most obvious difference between Polish and US shale resources is the depth range, which immediately translates into higher drilling costs for the deeper Polish reservoirs (exhibits 108 and 109). However, the ultimate recoverable gas-per-well is basically an unknown quantity for Polish (or indeed, European) developments as yet. It took at least a decade of intensive experimentation in the US to determine the "code", or best way to drill, fracture, and complete each particular shale play. We expect the learning curve in Europe to be similarly challenging.

Exhibit 108

Initial Data Broadly Analogous to US Basins

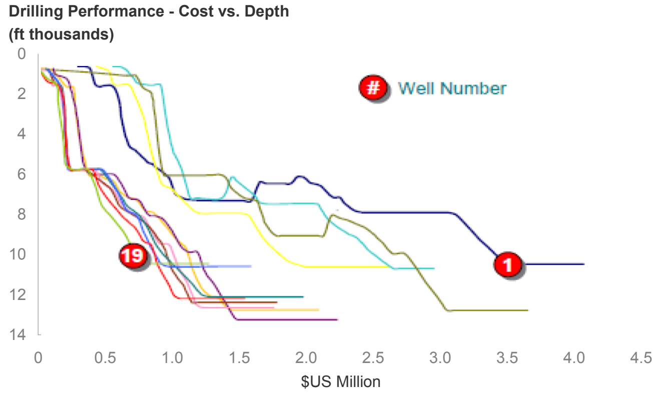
	Major EU Shale Plays		Shale Analogues		
	Polish Shale	**Paris Basin**	**Marcellus**	**Bakken**	**Barnett**
Depth (ft)	7000-12500	8000-13000	4000-8000	8000-10000	6500-8500
Net Thickness (ft)	200-800	4-130	50-250	5-70	450-525
TOC	0.7-9.9	0-12	0.4-10.5	0-40	4.5
Porosity%	4-8	up to 12%	1.6-7.0	8-12	4.5
Gas in Place (bcf/section)	200+	500kboe	40-130	400-1000kboe	50-150
EUR per well (bcf)	~20		4.2		2.7
Avg. Well Cost ($, m)	19	5-7	4.5	6-10	2.6

Source: Talisman Energy, BNK Petroleum, Aurelian, Toreador

The impact of the learning experience in the US is clear in exhibits 109 and 110, where, not surprisingly, well costs increase with depth and tend to fall as experience is gained and the number of wells drilled rises.

Exhibit 109

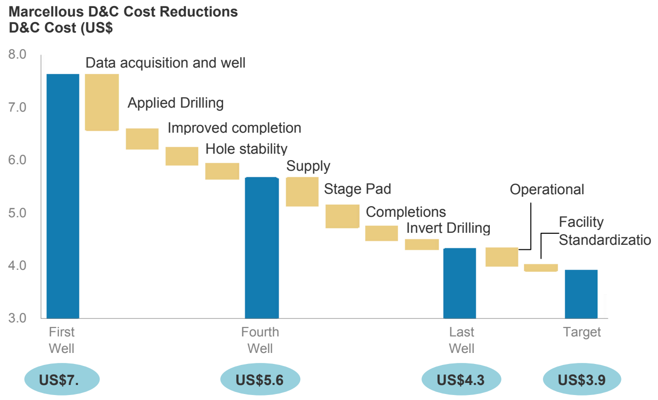
Initial Drilling Will be Expensive



Source: Talisman Energy data, Morgan Stanley Research. Note: The above chart refers to estimated costs for Marcellus Shale

Exhibit 110

… With Cost Reductions a Gradual Process



Source: Talisman Energy data, Morgan Stanley Research

Other Challenges for Aspiring European Shale Gas Developers Include:

- Geology: Different geographic ages and relatively complex structures in Europe.
- Environmental constraints: Europe has a much higher population density than does the US and a large amount of water is needed for fracturing.
- Economics: higher estimated well costs (because the wells are deeper than in US) and no clear fiscal regime in place to encourage shale gas investments. EON estimates a breakeven point of $10/mmbtu, against US shale gas $3-$7/mmbtu.

Appendix C – LNG Supply Base Case (Existing, Under Construction + Committed)

Existing and Expanding by Train

Country	Name	Operator/Buyer	Started	Trains	2003	2004	2005	2006	2007	2008	2009	2010E	2011E	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Algeria	Gassi Touil-GNL3	Repsol YPF, Gas Natural, Sonatrach	2012E	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Algeria	Bethioua	Sonatrach	1978	12	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Algeria	Azrew	Sonatrach	1965	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Algeria	Skikda re-build	Sonatrach	2013E	1	3	3	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
Algeria	Skikda (GL1K), Phase '	Sonatrach	1972 / 81	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Algeria				**17**	**23**	**23**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**
Angola	**Soyo**	**Chevron, Sonangol, TOTAL, BP, ENI**	**2012E**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**4**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
Australia	Darwin LNG	ConocoPhillips	2006	1	-	-	-	2	3	3	3	4	4	4	4	4	4	4	4	4	4	4
Australia	Pluto1	Woodside, Tokyo Gas, Kansai Electric	2011E	1	-	-	-	-	-	-	-	-	3	4	4	4	4	4	4	4	4	4
Australia	Burrup (NWS Train 1-5)	Woodside, BHP, BP, Chevron, Shell, MIMI	1989 / 04	5	8	11	13	13	13	13	16	16	16	16	16	16	16	16	16	16	16	16
Australia	Gorgon (3 t)	Chevron, ExxonMobil, Shell	2015E	3	-	-	-	-	-	-	-	-	-	-	-	-	4	8	12	15	15	15
Australia	Wheatstone	Chevron, Apache, Kufpec, TEPCO	2016E	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	9	9
Australia	Gladstone-GLNG (2 t)	Santos /Total /Petronas / kogas	2015E	2	-	-	-	-	-	-	-	-	-	-	-	-	3	5	7	7	7	7
Australia	APLNG (2 train)	Conoco, Origin, Sinopec	2015E	2	-	-	-	-	-	-	-	-	-	-	-	-	5	9	9	9	9	9
Australia	Gladstone-QCLNG (2 t)	BG, CNOOC	2014E	2	-	-	-	-	-	-	-	-	-	-	-	4	7	9	9	9	9	9
Australia				**18**	**8**	**11**	**13**	**15**	**16**	**16**	**19**	**19**	**22**	**24**	**24**	**28**	**42**	**54**	**65**	**72**	**72**	**72**
Brunei	**Lumut Train 1-5**	**Brunei LNG**	**1972**	**6**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**
Egypt	Damietta I	SEGAS (Union Fenosa/ENI, EGAS, EGPC)	2005	1	-	-	3	4	3	3	3	3	3	4	4	4	5	5	5	5	5	5
Egypt	Idku Train 1	BG , Edison , EGPC, Petronas, GDF	2005	1	-	-	2	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4
Egypt	Idku Train 2	BG , Edison , EGPC	2006	1	-	-	1	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4
Egypt				**3**	**0**	**0**	**6**	**11**	**10**	**10**	**9**	**9**	**9**	**11**	**11**	**11**	**12**	**12**	**12**	**12**	**12**	**12**
Equatorial Guinea	**Bioko Island**	**Marathon, GEpetrol**	**2007**	**1**	**0**	**0**	**0**	**0**	**4**	**4**	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Indonesia	Arun	Pertamina, ExxonMobil	1977 / 86	4	8	8	4	3	3	2	2	2	2	1	0	0	0	0	0	0	0	0
Indonesia	Sengkang	Energy World Corp	2013	4	-	-	-	-	-	-	0	0	0	0	1	1	1	1	2	2	2	2
Indonesia	Tangguh	BP, Nippon Oil, Japan LNG, CNOOC	2010	2	-	-	-	-	-	-	1	5	8	8	8	8	8	8	8	8	8	8
Indonesia	Donggi-Senoro	Mitsubishi, KOGAS	2014E	1	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2
Indonesia	Bontang Train A-H	Pertamina, Total, Unocal	1977	8	22	22	20	19	18	18	18	16	15	15	14	13	12	7	7	7	7	1
Indonesia				**19**	**30**	**30**	**24**	**23**	**21**	**21**	**20**	**23**	**25**	**23**	**22**	**23**	**22**	**18**	**19**	**19**	**19**	**13**
Libya	**Marsa El Brega**	**NOC (Sirte Oil Co.)**	**1970**	**3**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Malaysia	Bintulu MLNG (Satu)	Petronas, Shell	1983	3	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Malaysia	Bintulu MLNG (Dua)	Petronas, Shell	1995	3	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Malaysia	Bintulu MLNG (Tiga)	Petronas, Shell	2003	2	8	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Malaysia	Bintulu - MLNG 4	Petron., Sarawak Gov, Shell, Nippon Oil anc	??	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Malaysia				**8**	**24**	**21**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**
Nigeria	Bonny Island - 1 & 2	Nigeria LNG Ltd.	1999	1	6	6	6	6	6	5	3	4	5	6	6	6	6	6	6	6	6	6
Nigeria	Bonny Island - 3	Nigeria LNG Ltd.	2002	1	3	3	3	3	3	3	2	2	3	3	3	3	3	3	3	3	3	3
Nigeria	Bonny Island - 4 & 5	Nigeria LNG Ltd.	2005/6	1	0	0	5	8	8	7	5	5	7	8	8	8	8	8	8	8	8	8
Nigeria				**4**	**10**	**10**	**14**	**17**	**17**	**17**	**12**	**14**	**18**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**
Norway	**Snohvit**	**Statoil**		**1**	**0**	**0**	**0**	**0**	**0**	**2**	**3**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
Oman	Qalhat LNG 1 &2	Shell, Total, Korea LNG, Mimi, Partex, Itochı	2000	2	7	7	7	7	7	6	6	5	5	5	5	5	5	5	5	5	5	5
Oman	Qalhat LNG 3	Shell, Total, Korea LNG, Mimi, Partex, Itochı	2006	1	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Oman				**3**	**7**	**7**	**7**	**10**	**10**	**10**	**10**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
PNG	**PNG LNG**	**Exxon / OilSearch /Santos**		**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**7**	**7**	**7**	**7**	**7**	**7**
Peru	**Camisea**	**Hunt Oil, SK Corp**		**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
Qatar	Qatargas 1(Ras Laffan1	QP, Total, XOM, Mitsui, Marubeni	1997	3	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Qatar	RasGas1	QP(63), XOM (25), Kogas, Itochu, JapanLN(	1997	2	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Qatar	RasGas2-train3	QP 70, XOM 30	2004	1	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Qatar	RasGas2-train4	QP 70, XOM 30	2005	1	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Qatar	RasGas2-train5	QP 70, XOM 30	2007	1	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5
Qatar	RasGas3- train6	QP 70, XOM 30	2009	1	-	-	-	-	-	-	8	8	8	8	8	8	8	8	8	8	8	8
Qatar	RasGas3- train7	QP 70, XOM 30	2009	1	-	-	-	-	-	-	-	6	8	8	8	8	8	8	8	8	8	8
Qatar	Qatargas-2-train4	QP 70, XOM 30	2009	1	-	-	-	-	-	-	-	8	8	8	8	8	8	8	8	8	8	8
Qatar	Qatargas-2-train5	QP 70, XOM 30	2010	1	-	-	-	-	-	-	0	4	6	8	8	8	8	8	8	8	8	8
Qatar	Qatargas 3 (train 6)	QP68.6, COP 30, Mitsui 1.5	2010	1	-	-	-	-	-	-	-	1	8	8	8	8	8	8	8	8	8	8
Qatar	Qatargas 4 Train 7)	QP70, shell 30	2011	1	-	-	-	-	-	-	-	-	5	8	8	8	8	8	8	8	8	8
Qatar				**14**	**16**	**16**	**21**	**26**	**26**	**30**	**39**	**57**	**73**	**77**	**77**	**77**	**77**	**77**	**77**	**77**	**77**	**77**
Russia	Sakhalin II	Shell, Mitsui, Mitsubishi, Gazprom, Rosneft	2009	2	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10	10	10
Russia	Yamal LNG	Yamal LNG, Total, Novatek, Volga	2016E	2	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8	8	8	8
Russia	Shtokman	Total, Gazprom	2016E	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	4	4	4
Russia				**5**	**0**	**0**	**0**	**0**	**0**	**0**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**17**	**19**	**21**	**21**	**21**
Trinidad	Atlantic LNG - 4	BP, BG, Repsol, NGC	2006	1	-	-	-	3	4	4	5	5	5	5	5	5	5	5	5	5	5	5
Trinidad	Atlantic train 1	BP, BG, Repsol	1999	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Trinidad	Atlantic train 2	BP, BG, Repsol	2002	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Trinidad	Atlantic train 3	BP, BG, Repsol	2003	1	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Trinidad				**4**	**7**	**10**	**10**	**13**	**14**	**14**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**
Abu Dhabi	**Das Island I, II**	**ADGAS**		**3**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
Canada	**Kitmat**	**Apache, EOG**	**2015E**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**5**	**5**	**5**	**5**
USA	Kenai	Marathon, ConocoPhillips	1969	2	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
USA	Cheniere	Cheniere Energy	2015e		-	-	-	-	-	-	-	-	-	-	-	-	4	4	4	4	4	4
United States				**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**4**	**4**	**4**	**4**	**4**	**4**
Yemen	**Yemen LNG**	**Total, Hunt, SKCorp, Kogas, Hyundai**		**2**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**4**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**7**
World LNG Capacity (existing or under construction)				**116**	**140**	**143**	**152**	**171**	**176**	**182**	**199**	**227**	**255**	**265**	**272**	**281**	**302**	**323**	**336**	**345**	**346**	**339**

Source: WMAC, CERA, BP Stat Review, Morgan Stanley Research estimates (E)

Appendix D: Morgan Stanley Global Gas Exposure Basket Constituents (Bloomberg ticker: <MSSTLGAS>)

Morgan Stanley has created a trading basket containing 17 stocks we believe are most positively leveraged to the longer-term themes outlined in this report. The stocks are modified equal-weighted (adjusted for liquidity) and the basket is denominated in EUR.

Company	Ticker	Currency	Price	Weight
BG Group	BG/ LN	GBP	14.60	9.36%
CGG Veritas	GA FP	EUR	24.74	3.82%
Chevron	CVX US	USD	99.93	9.15%
China National Offshore	883 HK	HKD	17.90	8.87%
Dow Chemical	DOW US	USD	36.79	8.95%
Gazprom	OGZD LI	USD	29.23	9.12%
GCL-Poly Energy	3800 HK	HKD	3.85	3.69%
Interoil Corp	IOC US	USD	70.07	2.22%
Kunlun Energy	135 HK	HKD	11.78	2.11%
LyondellBasell	LYB US	USD	39.16	9.00%
Oil Search	OSH AU	AUD	6.62	2.20%
Petronas Chemicals	PCHEM MK	MYR	6.75	3.75%
Reliance Industries	RIL IN	INR	1,017.65	2.17%
Saipem	SPM IM	EUR	35.92	9.06%
Santos	STO AU	AUD	14.16	3.83%
SBM Offshore	SBMO NA	EUR	18.52	3.83%
Trina Solar	TSL US	USD	24.23	8.88%

Source: Morgan Stanley Research

An Investable Basket: Morgan Stanley Research has created a basket of the 17 stocks that we believe are most leveraged to the themes outlined in this report. The basket of 17 stocks can be viewed on Bloomberg under the symbol MSSTLGAS.

The information contained herein has been prepared solely for informational purposes and is not a solicitation of any offer to buy or sell any security or other financial instrument or to participate in any trading strategy. Products and trades of this type may not be appropriate for every investor. Please consult with your legal and tax advisors before making any investment decision.

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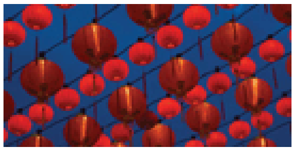

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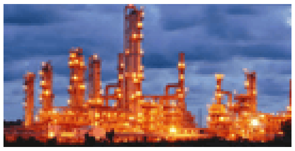

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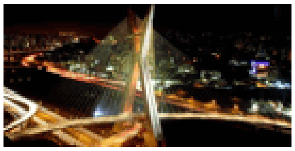

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